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Nos. 89-196 and 89-394

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IN THE

Supreme Court of the United States

OCTOBER TERM, 1989

RAILROAD COMMISSION OF TEXAS,
Petitioner,
v.

FEDERAL ENERGY REGULATORY COMMISSION, *et al.*,
Respondents.

WALKER OPERATING CORPORATION, *et al.*,
Petitioners,
v.

FEDERAL ENERGY REGULATORY COMMISSION, *et al.*,
Respondents.

On Petition for a Writ of Certiorari to the United States Court of Appeals for the Tenth Circuit

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APPENDIX TO BRIEF IN OPPOSITION OF RESPONDENTS DORCHESTER MASTER LIMITED PARTNERSHIP, NATURAL GAS PIPELINE COMPANY OF AMERICA, AND NORTHERN NATURAL GAS COMPANY, DIVISION OF ENRON CORP.

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APPENDIX TABLE OF CONTENTS

Page

APPENDIX A

Rule 28.1 Listings 1a

APPENDIX B

Natural Gas Act 9a

APPENDIX C

Natural Gas Policy Act 14a

APPENDIX D

Federal Energy Regulatory Commission Regulations 49a

APPENDIX E

Order Initiating Show Cause Proceeding 51a

APPENDIX F

Motion to Compel Denied 69a

APPENDIX G

Proposal For Decision 72a

APPENDIX A

RULE 28.1 LISTINGS

DORCHESTER MASTER LIMITED PARTNERSHIP

Dorchester Master Limited Partnership is the successor in interest to Dorchester Gas Producing Company, a party to the proceedings before the Federal Energy Regulatory Commission. Dorchester Master Limited Partnership has no subsidiaries or affiliates. Damson Oil Corporation is the general partner of Dorchester Master Limited Partnership.

NATURAL GAS PIPELINE COMPANY OF AMERICA

Natural Gas Pipeline Company of America is a subsidiary of MidCon Corp., 701 East 22nd Street, Lombard, Illinois, 60148, which, in turn, is a wholly-owned subsidiary of Occidental Petroleum Corporation, 10889 Wilshire Boulevard, Los Angeles, California, 90024.

Occidental Petroleum Corporation direct or indirect subsidiaries that are owned less than one hundred percent are:

Church & Dwight Co., Inc.
Energy America Incorporated
IBP, Inc.
Rail to Water Transfer Corporation
Primex Ltd.
Carbocloro S.A. Industrial Quimicas
Sanital Comercio e Empreendimentos Ltda.
Ftaliquimica S.A.
Oxypar Industries Quimicas S.A.
Malharia Industrial do Nordeste S.A.
Vinor Vinilicos do Nordeste Ltda.
Industrias Oxy S.A. de C.V.
Sumitomo Durez Co. Ltd.
Diamond Shamrock Chemicals Company Pty. Limited
Canadian Occidental Petroleum Ltd.
Fertilizer Belgium S.A.
International Ore and Fertilizer S.p.A.
Industria Quimica de Portugesa, S.A.

Mississippi Chemical Corporation
Tororo Industrial Chemicals and Fertilizers, Ltd.
Occidental Chemical China, Ltd.
Occidental Far East Limited
Occidental Chemical Chile, S.A.I.
Occidental Chemical New Zealand Limited
Thai Occidental Chemical Ltd.
Thai Diamond Shamrock Ltd.
Trans-Jeff Chemical Corporation
Oxy Metal Industries (France) S.A.
OXYTECH Systems, Inc.
Island Creek of China Coal, Ltd.
O-K Investment Company, Ltd.
Minera Azteca, S.A. de C.V.
Occidental Minerals (Philippines), Inc.
C-D Development Corporation
Newco Holding Corporation
Citco Amazonas Petroleo Ltda
Citco Barreirinhas Petroleo do Brasil Ltda
Citco Rio Petroleo Ltda
Petroleo de Brasil Ltda
East Texas Salt Water Disposal Company
Dixie Pipeline Company
Occidental of Aruba, Inc.
602 Operating Corporation
Oil Casualty Insurance, Ltd.
Oil Insurance Limited
Hispano Inversion, S.A.
Occidental de Espana, S.A.
Petway Products Distributors, Inc.
Hybrid Rice, Inc.
RAMM Hybrids International, Inc.
RAMM Hybrids, Inc.
Carter Day Industries, Inc.
Eko Hotels, Ltd.
Natural Gas Pipeline Company of America
Hazox Alternate Energy, Inc.
Hazox Corporation
Kildeer Area Development Corporation

NORTHERN NATURAL GAS COMPANY, DIVISION OF ENRON CORP.

Northern Natural Gas Company is a division of Enron Corp. Subsidiaries, affiliates, and divisions of Enron Corp. are:

Ajax Corporation (Massachusetts)
    The Apollo Group, Inc. (Massachusetts)
Belco Petroleum Corporation (Delaware)
    Belco Petroleum International, Ltd. (Delaware)
        Belco Petroleum Latin America, S.A. (Delaware)
            Belco Petroleum Corporation of Peru (Delaware)
    Belco Petroleum of Israel, Ltd. (Delaware)
        Sonneborn Associates Petroleum Corporation (Delaware)
    Belcoal Inc. (Delaware)
Enron Americas, Inc. (Delaware)
    Enron Peru, Inc. (Delaware
Enron Arctic Gas Company (Delaware)
Enron Art Foundation (Nebraska)
Enron Capital Corp. (Delaware)
Enron Coal Company (Delaware)
Enron Coal Pipeline Company (Delaware)
Enron Data Processing Company (Texas)
Enron Foundation—Houston (Texas)
Enron Foundation—Omaha (Nebraska)
Enron Gas Gathering, Inc. (Delaware)
    Enron Natural Gas Gathering Co. (Texas)
Enron Gas Marketing, Inc. (Delaware)
Enron Gas Processing Company (Delaware)
Enron Gas Production Company (Texas)
Enron Gas Services Company (Delaware)
Enron Gas Supply Company (Delaware)
Enron Gas Transportation Company (Delaware)
Enron Helium Company (Delaware)
Enron Holdings, Inc. (Delaware)
Enron International Incorporation (Delaware)

Enron Gas Liquids International (U.K.), Ltd.
Enron Gas Liquids France S.A.R.L. (France) (Formerly NLFI France S.A.R.L.)
NLFI (Far East) Trading Private Limited (Singapore) (To Be Dissolved)
IPI Orient Ltd. (Hong Kong) (To Be Dissolved)
Enron Oil Corp. (Delaware)
Enron Oil Ltd. (Partnership) (London)
Enron Oil PTE Ltd. (Singapore)
The Protane Corporation
Citadel Corporation Limited (Cayman Island)
Citadel Venezolana S.A. (Venezuela)
Industrial Gases Limited (Jamaica)
Manufacturera de Aparatos Domesticos, S.A. (Madosa) Venezuela
Industrias Ventane, S.A. (Venezuela)
Industrial Lacarda, S.A. (Venezuela)
Servicios Consolidados Ventane, S.A. (Venezuela)
Servicios Vengas, S.A. (Venezuela)
Transporte Mil Ruedas, S.A. (Venezuela)
Vengas de Caracas (Venezuela)
Vengas del Centro, S.A. (Venezuela)
Vengas de Occidente, S.A. (Venezuela)
Vengas de Oriente, S.A. (Venezuela)
ProCaribe, Inc. (Puerto Rico)
ProCaribe Division of The Protane Corporation
Progasco, Inc. (Puerto Rico)
Enron Gas Liquids, Inc. (Delaware)
Weddell Corporation (Liberia)
Enron Liquids Pipeline Company (Delaware)
Enron Minerals Company (Delaware)
Enron Mobile Bay, Inc. (Texas)
Enron NGL Corp. (Delaware)

Enron Oil & Gas Company (Delaware)
Enron Exploration Company (Texas)
Enron Oil Egypt Inc. (Texas)
Enron Oil Syria Inc. (Texas)
Enron Oil & Gas Marketing, Inc. (Texas)
Enron Oil Malaysia Inc.
IN Holdings, Inc. (Delaware)
Enron Oil Canada, Ltd. (Alberta, Canada)
Enron Oil Trading & Transportation Company (Delaware)
Enron Oil Pipeline Company (A Division)
Enron Oil Trading & Transportation Canada Ltd. (Canada)
Webster Transportation Company, Inc. (Louisiana)
Enron Overthrust Pipeline Company (Delaware)
Enron Power Corp.
Enron Power Enterprise Corp.
Enron Trailblazer Pipeline Company (Delaware)
Houston Pipe Line Company (Texas)
The Bermuda Company (Texas)
Gulf Company Ltd. (Bermuda)
Black Marlin Pipeline Company (Texas)
Coal Properties Corporation (Illinois)
Comanche Marketing, Inc. (Texas)
Cora Dock Corporation (Texas)
Enron Clearing House Company (Texas)
Enron Co-Gen Fuels Company (Texas)
Enron Gas Pipeline Operating Company
Enron Industrial Natural Gas Company (Texas)
Enron Interstate Pipeline Company (Delaware)
Enron Mojave, Inc. (Texas)
Enron Texoma Gas Company (Texas)
HNG Capital Corp. (Delaware)
HNG Holdings Corp. (Texas)
IDT Gas Supply Company (Texas)
Katy-Waha Gas Marketing Company (Texas)

Intratex Gas Company (Texas)
Natural Gas Marketing & Storage Company (Texas)
Pacific Atlantic Marketing, Inc. (Texas)
Panhandle Gas Company (Texas)
Pott Industries Inc. (Missouri)
Marcoal Inc. (W. Virginia)
Riverside Farms Company (Illinois)
Transgulf Pipeline Company (Florida)
Transwestern Pipeline Company (Delaware)
Valley Pipe Lines, Inc. (Texas)
Valley Pipe Lines Offshore Division (Assumed Name)
Webb-Duval Pipeline, Inc. (Delaware)
KMC Associates, Incorporated (Colorado)
NGP Pipeline Company (Delaware)
Northern Intrastate Pipeline Company (Delaware)
Northern Natural Gas Supply Company (Delaware)
Northern Plains Natural Gas Company (Delaware)
AmNorth, Inc. (Nebraska)
Pathfinder Assurance Limited (Bermuda)

Divisions of Enron Corp.:

Enron EOR Services Company
Enron International Developmental Division
Gas Pipeline Group Division
Information Management Division
Northern Natural Gas Company Division
San Juan Gas Company Division

Joint Venture Companies:

Citrus Corp. (Delaware)
Owned by Sonat—50% (Class A Stock)
Houston Pipe Line—50% (Class B Stock)
Citrus Interstate Pipeline Company (Delaware)
Citrus Industrial Sales Company, Inc. (Delaware)

Citrus Marketing, Inc. (Florida)
Citrus Trading Corp. (Delaware)
Florida Gas Transmission Company (Delaware)

Enron/Dominion Cogen Corp. (Delaware)
Owned by Enron—50%
Dominion Resources—50%
Cogenron Inc. (Delaware)
(EC1C owns 100% of common; Outside Investors own 100% of preferred stock)
Enron Bayou Co-Gen, Inc. (Texas)
Enron Cogeneration One Company (Delaware)
Enron Cogeneration Two Company (Delaware)
Enron Cogeneration Three Company (Delaware)
Enron Cogeneration Four Company (Delaware)
Enron Cogeneration Five Company (Delaware)
Enron Cogeneration Resources Company (Delaware)
Enron Cogeneration Six Company (Delaware)

Enron NGL Processing Limited Partnership (Delaware)

HT Gathering Company (Texas)
Class A Voting Common Stock—50/50 Tenngasco and Houston Pipe Line
Class B Common Stock—100% Houston Pipe Line

Jubilee Pipeline Company (Texas)
An Unincorporated Joint Venture among:
Oklahoma Gas Pipeline Company—35%
Enron Mobile Bay, Inc.—22.5%
Tabasco Gas Pipe Line Company—15%
Sonat Mobile Bay Inc.—12.5%
Odeco Gas Gathering Inc.—7.5%
Murphy Gas Gathering Inc.—7.5%

Mojave Pipeline Operating Company (Texas)
Owned by Mojave Pipeline Company, a Partnership composed of:
Enron Mojave, Inc.—50% and
El Paso Mojave—50%

Norelf Limited (Bermuda)
Owned by Enron Gas Liquids Inc.—42.5%
Corelf—42.5%
Gazocean (Bermuda) Trading Ltd.—15%

Northern Border Pipeline Company (Texas)
Owned by Northern Plains Natural Gas Company—22.75%
Pan Border Gas Company—22.75%
TransCanada Border PipeLine Ltd.—30%
United Mid-Continent Pipeline Company—12.25%
Norwest Border Pipeline Company—12.25%

Oasis Pipe Line Company (Delaware)
Owned by Houston Pipe Line Company
The Dow Chemical Company and
Tenngasco Gas Supply Company

San Marco Pipeline Company (Colorado)
Owned by Houston Pipe Line Company—50%
The Denver & Rio Grande Western Railroad Co.—50%

Seagull Shoreline System (A Texas Partnership composed of Northern Intrastate Pipeline Company, Texas Eastern Offshore Company and Seagull Transmission Company)

The Standard Shale Products Company (Colorado)
Owned by Conoco—70%
Houston Pipe Line Company—30%

Zapata Gulf Marine Corporation (Delaware)
Owned by Houston Pipe Line Company—360 shares—Class A
Zapata Corporation—426 shares—Class B
Halliburton Company—214 shares—Class C

APPENDIX B

NATURAL GAS ACT 15 U.S.C. §§ 717 *et seq.*

§ 717. Necessity for regulation of natural gas companies

(a) As disclosed in reports of the Federal Trade Commission made pursuant to S. Res. 83 (Seventieth Congress, first session) and other reports made pursuant to the authority of Congress, it is declared that the business of transporting and selling natural gas for ultimate distribution to the public is affected with a public interest, and that Federal regulation in matters relating to the transportation of natural gas and the sale thereof in interstate and foreign commerce is necessary in the public interest.

(b) The provisions of this chapter shall apply to the transportation of natural gas in interstate commerce, to the sale in interstate commerce of natural gas for resale for ultimate public consumption for domestic, commercial, industrial, or any other use, and to natural-gas companies engaged in such transportation or sale, but shall not apply to any other transportation or sale of natural gas or to the local distribution of natural gas or to the facilities used for such distribution or to the production or gathering of natural gas.

(c) The provisions of this chapter shall not apply to any person engaged in or legally authorized to engage in the transportation in interstate commerce or the sale in interstate commerce for resale, of natural gas received by such person from another person within or at the boundary of a State if all the natural gas so received is ultimately consumed within such State, or to any facilities used by such person for such transportation or sale, provided that the rates and service of such person and facilities be subject to regulation by a State commission. The matters exempted from the provisions of this chapter by this subsection are declared to be matters primarily

of local concern and subject to regulation by the several States. A certificaiton from such State commission to the Federal Power Commission that such State commission has regulatory jurisdiction over rates and service of such person and facilities and is exercising such jurisdiction shall constitute conclusive evidence of such regulatory power or jurisdiction.

June 21, 1938, c. 556, § 1, 52 Stat. 821; Mar. 27, 1954, c. 115, 68 Stat. 36.

§ 717f. Construction, extension, or abandonment of facilities; certificate of convenience and necessity; condemnation proceedings

(a) Whenever the Commission, after notice and opportunity for hearing, finds such action necessary or desirable in the public interest, it may by order direct a natural-gas company to extend or improve its transportation facilities, to establish physical connection of its transportation facilities with the facilities of, and sell natural gas to, any person or municipality engaged or legally authorized to engage in the local distribution of natural or artificial gas to the public, and for such purpose to extend its transportation facilities to communities immediately adjacent to such facilities or to territory served by such natural-gas company, if the Commission finds that no undue burden will be placed upon such natural-gas company thereby: *Provided*, That the Commission shall have no authority to compel the enlargement of transportation facilities for such purposes, or to compel such natural-gas company to establish physical connection or sell natural gas when to do so would impair its ability to render adequate service to its customers.

(b) No natural-gas company shall abandon all or any portion of its facilities subject to the jurisdiction of the Commission, or any service rendered by means of such facilities, without the permission and approval of the Commission first had and obtained, after due hearing,

and a finding by the Commission that the available supply of natural gas is depleted to the extent that the continuance of service is unwarranted, or that the present or future public convenience or necessity permit such abandonment.

(c) No natural-gas company or person which will be a natural-gas company upon completion of any proposed construction or extension shall engage in the transportation or sale of natural gas, subject to the jurisdiction of the Commission, or undertake the construction or extension of any facilties therefor, or acquire or operate any such facilities or extensions thereof, unless there is in force with respect to such natural-gas company a certificate of public convenience and necessity issued by the Commission authorizing such acts or operations: *Provided, however,* That if any such natural-gas company or predecessor in interest was bona fide engaged in transportation or sale of natural gas, subject to the jurisdiction of the Commission, on February 7, 1942, over the route or routes or within the area for which application is made and has so operated since that time, the Commission shall issue such certificate without requiring further proof that public convenience and necessity will be served by such operation, and without further proceedings, if application for such certificate is made to the Commission within ninety days after February 7, 1942. Pending the determination of any such application, the continuance of such operation shall be lawful.

In all other cases the Commission shall set the matter for hearing and shall give such reasonable notice of the hearing thereon to all interested persons as in its judgment may be necessary under rules and regulations to be prescribed by the Commission; and the application shall be decided in accordance with the procedure provided in subsection (e) of this section and such certificate shall be issued or denied accordingly: *Provided, however,* That the Commission may issue a temporary certificate in cases of emergency, to assure maintenance of adequate service

or to serve particular customers, without notice or hearing, pending the determination of an application for a certificate, and may by regulation exempt from the requirements of this section temporary acts or operations for which the issuance of a certificate will not be required in the public interest.

(d) Application for certificates shall be made in writing to the Commission, be verified under oath, and shall be in such form, contain such information, and notice thereof shall be served upon such interested parties and in such manner as the Commission shall, by regulation, require.

(e) Except in the cases governed by the provisos contained in subsection (c) of this section, a certificate shall be issued to any qualified applicant therefor, authorizing the whole or any part of the operation, sale, service, construction, extension, or acquisition covered by the application, if it is found that the applicant is able and willing properly to do the acts and to perform the service proposed and to conform to the provisions of this chapter and the requirements, rules, and regulations of the Commission thereunder, and that the proposed service, sale, operation, construction, extension, or acquisition, to the extent authorized by the certificate, is or will be required by the present or future public convenience and necessity; otherwise such application shall be denied. The Commission shall have the power to attach to the issuance of the certificate and to the exercise of the rights granted thereunder such reasonable terms and conditions as the public convenience and necessity may require.

(f) The Commission, after a hearing had upon its own motion or upon application, may determine the service area to which each authorization under this section is to be limited. Within such service area as determined by the Commission a natural-gas company may enlarge or extend its facilities for the purpose of supplying increased market demands in such service area without further authorization.

(g) Nothing contained in this section shall be construed as a limitation upon the power of the Commission to grant certificates of public convenience and necessity for service of an area already being served by another natural-gas company.

(h) When any holder of a certificate of public convenience and necessity cannot acquire by contract, or is unable to agree with the owner of property to the compensation to be paid for, the necessary right-of-way to construct, operate, and maintain a pipe line or pipe lines for the transportation of natural gas, and the necessary land or other property, in addition to right-of-way, for the location of compressor stations, pressure apparatus, or other stations or equipment necessary to the proper operation of such pipe line or pipe lines, it may acquire the same by the exercise of the right of eminent domain in the district court of the United States for the district in which such property may be located, or in the State courts. The practice and procedure in any action or proceeding for that purpose in the district court of the United States shall conform as nearly as may be with the practice and procedure in similar action or proceeding in the courts of the State where the propery is situated: *Provided*, That the United States district courts shall only have jurisdiction of cases when the amount claimed by the owner of the property to be condemned exceeds $3,000.

June 21, 1938, c. 556, § 7, 52 Stat. 824; Feb. 7, 1942, c. 49, 56 Stat. 83; July 25, 1947, c. 333, 61 Stat. 459.

APPENDIX C

NATURAL GAS POLICY ACT OF 1978
15 U.S.C. §§ 3301 *et seq.*

§ 3301. Definitions

For purposes of this chapter—

* * * *

(6) Reservoir.—The term "reservoir" means any producible natural accumulation of natural gas, crude oil, or both, confined—

(A) by impermeable rock or water barriers and characterized by a single natural pressure system; or

(B) by lithologic or structural barriers which prevent pressure communication.

* * * *

(8) Proration unit.—The term "proration unit" means—

(A) any portion of a reservoir, as designated by the State or Federal agency having regulatory jurisdiction with respect to production from such reservoir, which will be effectively and efficiently drained by a single well;

(B) any drilling unit, production unit, or comparable arrangement, designated or recognized by the State or Federal agency having jurisdiction with respect to production from the reservoir, to describe that portion of such reservoir which will be effectively and efficiently drained by a single well; or

(C) if such portion of a reservoir, unit, or comparable arrangement is not specifically provided for by State law or by any action of any State or Federal agency having regulatory jurisdiction with respect to production from such

reservoir, any voluntary unit agreement or other comparable arrangement applied, under local custom or practice within the locale in which such reservoir is situated, for the purpose of describing the portion of a reservoir which may be effectively and efficiently drained by a single well.

* * * *

(18) Committed or dedicated to interstate commerce.—

(A) General rule—The term "committed or dedicated to interstate commerce", when used with respect to natural gas, means—

(i) natural gas which is from the Outer Continental Shelf; and

(ii) natural gas which, if sold, would be required to be sold in interstate commerce (within the meaning of the Natural Gas Act) under the terms of any contract, any certificate under the Natural Gas Act, or any provision of such Act.

(B) Exclusion.—Such term does not apply with respect to—

(i) natural gas sold in interstate commerce (within the meaning of the Natural Gas Act)—

(I) under section 6 of the Emergency Natural Gas Act of 1977;

(II) under any limited term certificate, granted pursuant to section 7 of the Natural Gas Act, which contains a pregrant of abandonment of service for such natural gas;

(III) under any emergency regulation under the second proviso of section 7(c) of the Natural Gas Act; or

(IV) to the user by the producer and transported under any certificate, granted pursuant to section 7(c) of the Natural Gas Act, if such certificate was specifically granted for the transportation of that natural gas for such user;

(ii) natural gas for which abandonment of service was granted before November 9, 1978, under section 7 of the Natural Gas Act; and

(iii) natural gas which but for this clause, would be committed or dedicated to interstate commerce under subparagraph (A)(ii) by reason of the action of any person (including any successor in interest thereof, other than by means of any reversion of a leasehold interest), if on May 31, 1978—

(I) neither that person, nor any affiliate thereof, had any right to explore for, develop, produce, or sell such natural gas; and

(II) such natural gas was not being sold in interstate commerce (within the meaning of the Natural Gas Act) for resale (other than any sale described in clause (i)(I), (II), or (III)).

* * * *

(21) First Sale.—

(A) General rule.—The term "first sale" means any sale of any volume of natural gas—

(i) to any interstate pipeline or intrastate pipeline;

(ii) to any local distribuiton company;

(iii) to any person for use by such person;

(iv) which precedes any sale described in clauses (i), (ii), or (iii); and

(v) which precedes or follows any sale described in clauses (i), (ii), (iii), or (iv) and is defined by the Commission as a first sales in order to prevent circumvention of any maximum lawful price established under this chapter.

(B) Certain sales not included.—Clauses (i), (ii), (iii), or (iv) of subparagraph (A) shall not include the sale of any volume of natural gas by any interstate pipeline, intrastate pipeline, or local distribution company, or any affiliate thereof, unless such sale is attributable to volumes of natural gas produced by such interstate pipeline, intrastate pipeline, or local distribution company, or any affiliate thereof.

* * * *

SUBCHAPTER A—WELLHEAD PRICING

PART A—WELLHEAD PRICE CONTROLS

§ 3312. Ceiling price for new natural gas and certain natural gas produced from Outer Continental Shelf

(a) Application.—The maximum lawful price computed under subsection (b) of this section shall apply to any first sale of natural gas delivered during any month in the case of—

(1) new natural gas; and

(2) natural gas produced from any old lease on the Outer Continental Shelf and qualifying under subsection (d) of this section for the new natural gas ceiling price.

(b) Maximum lawful price.—The maximum lawful price under this section for any month shall be—

(1) $1.75 per million Btu's, in the case of April 1977; and

(2) in the case of any month thereafter, the maximum lawful price, per million Btu's, prescribed under this subsection for the preceding month multiplied by the monthly equivalent of a factor equal to the sum of—

(A) the annual inflation adjustment factor applicable for such month; plus

(B) (i) .035, in the case of any month beginning before April 20, 1981; or

(ii) .04, in the case of any month beginning after April 20, 1981.

(c) Definition of new natural gas.—

(1) General rule.—For the purposes of this section, the term "new natural gas" means each of the following categories of natural gas:

(A) New OCS leases.—Natural gas determined in accordance with section 3413 of this title to be produced from a new lease on the Outer Continental Shelf.

(B) New onshore wells.—Natural gas determined in accordance with section 3413 of this title to be produced (other than from the Outer Continental Shelf) from—

(i) any new well which is 2.5 miles or more (determined in accordance with paragraph (2)) from the nearest marker well;

or

(ii) any completion location, of any new well, which is located at a depth at least 1,000 feet below the deepest completion location of each marker well within 2.5 miles (determined in accordance with paragraph (2)) of such new well.

(C) New onshore reservoirs.—

(i) General rule.—Except as provided in clauses (ii) and (iii), natural gas determined in accordance with section 3413 of this title to be produced (other than from the Outer Continental Shelf) from a reservoir from which natural gas was not produced in commercial quantities before April 20, 1977.

(ii) Behind-the-pipe exclusion.—Clause (i) shall not apply to natural gas produced from any reservoir if—

(I) the reservoir was penetrated before April 20, 1977, by an old well from which natural gas or crude oil was produced in commercial quantities (whether or not such production was from such reservoir); and

(II) natural gas could be been produced in commercial quantities from such reservoir through such old well before April 20, 1977.

(iii) Withheld gas exclusion.—Clause (i) shall not apply to natural gas produced from any reservoir—

(I) if such natural gas is produced through an old well; and

(II) subject to clause (iv), suitable facilities for the production and deliv-

ery to a pipeline of such natural gas were in existence on April 20, 1977.

(iv) Emergency sale facilities.—The criteria of clause (iii) (II) shall not be considered to be met by reason of the existence of production and delivery facilities which were installed to carry out sales and deliveries of natural gas—

(I) under section 6 of the Emergency Natural Gas Act of 1977; or

(II) under the emergency sale authority pursuant to Opinion 699-B issued by the Federal Power Commission under section 7(c) of the Natural Gas Act.

(2) Determinations of distance.—For purposes of determining the distance from any new well to any marker well—

(A) Surface location to surface location.—The measurement shall be the horizontal distance from the surface location of the new well to the surface location of the marker well—

(i) in any case in which the new well meets requirements for the nondirectional drilling of wells prescribed by the appropriate State or Federal agency having regulatory jurisdiction over the drilling of such well; or

(ii) in any case in which—

(I) the surface drilling of such new well began on or after February 19, 1977;

(II) production of natural gas in commercial quantities began from such well before November 9, 1978; and

(III) the drilling of such well was not subject to any requirement regarding directional or nondirectional drilling, or the drilling of such well was subject to requirements regarding directional drilling but such requirement did not necessitate the obtaining of any permit or other certificate before drilling began.

(B) Completion location to surface location. —In the case of any new well which is not covered by subparagraph (A), the measurements shall be the horizontal distance from—

(i) the closest point of any completion location of the new well, vertically projected to the same elevation as the surface location of the nearest marker well; to

(ii) the surface location of such marker well.

(3) Determination of commercial quantities.— For purposes of determining whether production of natural gas has occurred in commercial quantities under paragraph (1)(C)—

(A) a rebuttable presumption exists that production from a reservoir in commercial quantities has not occurred if natural gas has not been sold and delivered from such reservoir before April 20, 1977; and

(B) quantities of natural gas sold in interstate commerce (within the meaning of the Natural Gas Act) shall not be taken into account if such quantities were sold before November 9, 1978—

(i) under section 6 of the Emergency Natural Gas Act of 1977; or

(ii) under the emergency sale authority pursuant to Opinion 699-B issued by the Federal Power Commission under section 7 (c) of the Natural Gas Act.

(4) New wells which are also marker wells.—For purposes of applying subsection (c) (1) (B) (ii) of this section in the case of any marker well which is also a new well under section 3301(3) (B) of this title, the reference in such subsection (c) (1) (B) (ii) of this section to the deepest completion location of any marker well shall be deemed to be a reference to any subsurface location from which natural gas was produced in commercial quantities after January 1, 1970, and before February 19, 1977.

(d) OCS gas qualifying for new natural gas ceiling price.—For purposes of this section—

(1) OCS reservoirs discovered on or after July 27, 1976.—Natural gas determined in accordance with section 3413 of this title to be produced from an old lease on the Outer Continental Shelf shall qualify for the new natural gas ceiling price if such natural gas is produced from a reservoir which was not discovered before July 27, 1976.

(2) Reservoirs penetrated before July 27, 1976.—For purposes of paragraph (1), a reservoir shall be considered as having been discovered before July 27, 1976, if—

(A) such reservoir was penetrated by a well before July 27, 1976; and

(B) with respect to such well—

(i) the results of any production test meeting the requirements of OCS Order No. 4 demonstrate that, as of the time of such test, the reservoir is capable of producing in

paying quantities (within the meaning of such Order);

(ii) any production capability evidence meeting the requirements of OCS Order No. 4 demonstrates that, as of the time such evidence is obtained, the reservoir is capable of producing in paying quantities (within the meaning of such Order); or

(iii) subject to paragraph (3), an induction-electric log, sidewall cores and core analysis, or a wire line formation test indicates that, as of the time of such test, the reservoir is commercially producible.

(3) Effect of negative production capability tests. —For purposes of paragraph (1), a reservoir shall not be considered as having been discovered before July 27, 1976, by the penetration of such reservoir by a well before July 27, 1976, if, with respect to such well—

(A) a production test meeting the requirements of OCS Order No. 4 was performed and the results of such test fail to demonstrate that, as of the time of such test, such reservior[1] was capable of producing in paying quantities (within the meaning of such Order); and

(b) production capability evidence meeting the requirements of OCS Order No. 4 does not exist or, if existing, does not demonstrate that, as of the date such evidence was obtained, such reservoir was capable of producing in paying quantities (within the meaning of such Order).

(4) Burden of proof.—For purposes of paragraph (1), the producer shall have the burden of showing that—

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[1] So in original. Probably should be "reservoir".

(A) no test described in paragraph (2)(B)(i) or (iii) was performed and no evidence described in paragraph (2)(B)(ii) or (iii) exists; or

(B) if any such test was performed or such evidence exists, the results of such test or such evidence do not provide the applicable demonstration or indication specified under paragraph (2).

(5) Definition of OCS Order No. 4.—For purposes of this subsection, the term "OCS Order No. 4" means the order numbered 4 of the Conservation Division, Geological Survey, Department of the Interior, as approved by the Chief of the Conservation Division on August 28, 1969.

(e) Exclusion of certain Alaska natural gas.—The preceding provisions of this section shall not apply to any natural gas produced from the Prudhoe Bay Unit of Alaska and transported through the natural gas transportation system approved under the Alaska Natural Gas Transportation Act of 1976.

(Pub.L. 95-621, Title I, § 102, Nov. 9, 1978, 92 Stat. 3358.)

§ 3313. Ceiling price for new, onshore production wells

(a) Application.—In the case of natural gas determined in accordance with section 3413 of this title to be produced from any new, onshore production well, the maximum lawful price computed under subsection (b) of this section shall apply to any first sale of such natural gas delivered during any month.

(b) Maximum lawful price.—

(1) General rule.—The maximum lawful price under this section for any month shall be—

(A) $1.75 per million Btu's, in the case of April 1977; and

(B) in the case of any month thereafter, the maximum lawful price, per million Btu's, prescribed under this paragraph for the preceding month multiplied by the monthly equivalent of the annual inflation adjustment factor applicable for such month.

(2) Production after 1984 from wells 5,000 feet or less in depth.—Effective beginning with the month of January 1985 and in any month thereafter, in the case of any first sale of natural gas which was not committed or dedicated to interstate commerce on April 20, 1977, and which is produced from a new, onshore production well from a completion location located at a depth of 5,000 feet or less, the maximum lawful price under this section for any such natural gas delivered during any month shall be a price which is midway between—

(A) the maximum lawful price, per million Btu's, computed for such month under section 3312 of this title (relating to new natural gas); and

(B) the maximum lawful price, per million Btu's, computed for such month under paragraph (1).

(c) Definition of new, onshore production well.—For purposes of this section, the term "new, onshore production well" means any new well (other than a well located on the Outer Continental Shelf)—

(1) the surface drilling of which began on or after February 19, 1977;

(2) which satisfies applicable Federal or State well-spacing requirements, if any; and

(3) which is not within a proration unit—

(A) which was in existence at the time the surface drilling of such well began;

(B) which was applicable to the reservoir from which such natural gas is produced; and

(C) which applied to a well (i) which produced natural gas in commercial quantities or (ii) the surface drilling of which was begun before February 19, 1977, and which was thereafter capable of producing natural gas in commercial quantities.

(d) Exclusion of certain Alaska natural gas.—The preceding provisions of this section shall not apply to any natural gas produced from the Prudhoe Bay Unit of Alaska and transported through the natural gas transportation system approved under the Alaska Natural Gas Transportation Act of 1976.

(Pub.L. 95-621, Title I, § 103, Nov. 9, 1978, 92 Stat. 3361.)

§ 3314. Ceiling price for sales of natural gas dedicated to interstate commerce

(a) Application.—In the case of natural gas committed or dedicated to interstate commerce on November 8, 1978, and for which a just and reasonable rate under the Natural Gas Act was in effect on such date for the first sale of such natural gas, the maximum lawful price computed under subsection (b) of this section shall apply to any first sale of such natural gas delivered during any month.

(b) Maximum lawful price.—

(1) General rule.—The maximum lawful price under this section for any month shall be the higher of—

(A) (i) the just and reasonable rate, per million Btu's, established by the Commission which was (or would have been) applicable to the first sale of such natural gas on April 20, 1977, in the case of April 1977; and

(ii) in the case of any month thereafter, the maximum lawful price, per million Btu's, prescribed under this subparagraph for the preceding month multiplied by the monthly equivalent of the annual inflation adjustment factor applicable for such month, or

(B) any just and reasonable rate which was established by the Commission after April 27, 1977, and before November 9, 1978, and which is applicable to such natural gas.

(2) Ceiling prices may be increased if just and reasonable.—The Commission may, by rule or order, prescribe a maximum lawful ceiling price, applicable to any first sale of any natural gas (or category thereof, as determined by the Commission) otherwise subject to the preceding provisions of this section, if such price is—

(A) higher than the maximum lawful price which would otherwise be applicable under such provisions; and

(B) just and reasonable within the meaning of the Natural Gas Act.

(Pub.L. 95-621, Title I, § 104, Nov. 9, 1978, 92 Stat. 3362.)

§ 3317. Ceiling price for high-cost natural gas

(a) Wells completed below 15,000 feet.—In the case of any first sale of high-cost natural gas produced from any well the surface drilling of which began on or after February 19, 1977, if such production from any comple-

tion location which is located at a depth of more than 15,000 feet, the maximum lawful price under this section for such natural gas delivered during any month shall be the maximum lawful price, per million Btu's, computed for such month under section 3312 of this title (relating to new natural gas).

(b) Commission authority to prescribe higher incentive prices.—The Commission may, by rule or order, prescribe a maximum lawful price, applicable to any first sale of any high-cost natural gas, which exceeds the otherwise applicable maximum lawful price to the extent that such special price is necessary to provide reasonable incentives for the production of such high-cost natural gas.

(c) Definition of high-cost natural gas.—For purposes of this section, the term "high-cost natural gas" means natural gas determined in accordance with section 3413 of this title to be—

(1) produced from any well the surface drilling of which began on or after February 19, 1977, if such production is from a completion location which is located at a depth of more than 15,000 feet;

(2) produced from geopressured brine;

(3) occluded natural gas produced from coal seams;

(4) produced from Devonian shale; and

(5) produced under such other conditions as the Commission determines to present extraordinary risks or costs.

(d) Provisions for high-cost natural gas to be elective. —if any credit, exemption, deduction, or comparable adjustment applicable to the computation of any Federal tax is specifically allowable with respect to any high-cost natural gas (or category thereof) under any provision of law enacted after November 9, 1978, the provisions of subsections (a) and (b) of this section and the provisions

of part B of this subchapter shall not apply to such natural gas produced from any well unless an election to have such provisions apply (in lieu of such credit, exemption, deduction, or adjustment) with respect to such natural gas produced from such well is filed with the Commission on or before the later of—

(A) the 30th day after November 9, 1978, under which such credit, exemption, deduction, or adjustment is provided; or

(B) the date the surface drilling of such well began.

(Pub.L. 95-621, Title I, § 707, Nov. 9, 1978, 92 Stat. 3366.)

§ 3318. Ceiling price for stripper well natural gas.

(a) General rule.—In the case of any first sale of stripper well natural gas the maximum lawful price under this section for such natural gas delivered during any month shall be—

(1) $2.09 per million Btu's, in the case of May 1978; and

(2) in the case of any month thereafter, the maximum lawful price, per million Btu's, prescribed under this subsection for the preceding month multiplied by the monthly equivalent of a factor equal to the sum of—

(A) the annual inflation adjustment factor applicable for such month; plus

(B)(i) .035, in the case of any month beginning before April 20, 1981; or

(ii) .04, in the case of any month beginning after April 20, 1981.

(b) Definition of stripper well natural gas.—

(1) General rule.—Except as provided in paragraph (2), the term "stripper well natural gas" means natural gas determined in accordance with section 3413 of this title to be nonassociated natural gas produced during any month from a well if—

(A) during the preceding 90-day production period, such well produced nonassociated natural gas at a rate which did not exceed an average of 60 Mcf per production day during such period; and

(B) during such period such well produced at its maximum efficient rate of flow, determined in accordance with recognized conservation practices designed to maximize the ultimate recovery of natural gas.

(2) Production in excess of 60 Mcf.—The Commission shall, by rule, provide that, if nonassociated natural gas produced from a well which previously qualified as a stripper well under paragraph (1) exceeds an average of 60 Mcf per production day during any 90-day production period, such natural gas may continue to qualify as stripper well natural gas if the increase in nonassociated natural gas produced from such well was the result of the application of recognized enhanced recovery techniques.

(3) Definitions.—For purposes of this subsection—

(A) Production day.—The term "production day" means—

(i) any day during which natural gas is produced; and

(ii) any day during which natural gas is not produced if production such day is prohibited by a requirement of State law or a conservation practice recognized or ap-

proved by the State agency having regulatory jurisdiction over the production of natural gas.

(B) 90-day production period.—The term "90-day production period" means any period of 90 consecutive calendar days excluding any day during which natural gas is not produced for reasons other than voluntary action of any person with the right to control production of natural gas from such well.

(C) Nonassociated natural gas.—The term "nonassociated natural gas" means natural gas which is not produced in association with crude oil.

(Pub.L. 95-621, Title I, § 108, Nov. 9, 1978, 92 Stat. 3367.)

§ 3413. Determinations for qualifying under certain categories of natural gas

(a) General rule.—

(1) Determination.—If any State or Federal agency makes any final determination which it is authorized to make under subsection (c) of this section for purposes of—

(A) applying the definition of new natural gas under section 3312(c) of this title;

(B) deciding if certain natural gas produced from the Outer Continental Shelf qualifies under section 3312(d) of this title for the new natural gas ceiling price;

(C) applying the definition of new, onshore production-well under section 3313(c) of this title;

(D) applying the definition of high-cost natural gas under section 317(c) of this title; or

(E) applying the definition of stripper well natural gas under section 3318(b) of this title;

such determination shall be applicable under this chapter for such purposes unless such determination is reversed under the provisions of subsection (b) of this section or unless such State or Federal agency has waived its authority under the provisions of subsection (c) of this section.

(2) Notice to Commission.—Any Federal or State agency making a determination under paragraph (1) shall provide timely notice in writing of such determination to the Commission. Such notice shall include such substantiation and be in such a manner as the Commission may, by rule, require.

(b) Commission review.—

(1) Authority to review and reverse.—The Commission shall reverse any final State or Federal agency determination described in subsection (a) of this section if—

(A) it makes a finding that such determination is not supported by substantial evidence in the record upon which such determination was made; and

(B) such preliminary finding and notice thereof under paragraph (3) is made within 45 days after the date on which the Commission received notice of such determination under subsection (a)(2) of this section and the final such finding is made within 120 days after the date of the preliminary finding.

(2) Remand on basis of Commission information.—If—

(A) the Commission finds that a State or Federal agency determination is not consistent with information contained in the public records of the Commission, and which is not part of the record upon which such determination was made; and

(B) such preliminary finding and notice thereof under paragraph (3) is made within 45 days after the date on which the Commission received notice of such determination under subsection (a) (2) of this section and the final such finding is made within 120 days after the date of the preliminary finding,

it may remand the matter to such State or Federal agency for consideration of such information. If such agency, after consideration of the information transmitted to it by the Commission, affirms its previous determination, such determination, as so affirmed, shall be subject to review in accordance with this subsection (other than this paragraph).

(3) Notice.—The Commission shall provide notice of any proposed finding under this subsection to the State or Federal agency which made such determination and those parties identified in the notice to the Commission of such determination.

(4) Judicial review of Commission actions.—

(A) Remands.—Any party identified in the notice to the Commission of a determination by a State or Federal agency may obtain review of any final decision by the Commission to remand under paragraph (2) in the United States Court of Appeals for any circuit in which such party is located or has its principal place of business, or in the United States Court of Appeals for the District of Columbia circuit. The reviewing

court shall reverse any such decision if it finds such decision is arbitrary or capricious.

(B) Findings.—Any person aggrieved or adversely affected by a final finding of the Commission under paragraph (1) may within 60 days thereafter file a petition for review of such finding in the United States Court of Appeals for any circuit in which the party involved in such determination is located or has its principal place of business, or in the United States Court of Appeals for the District of Columbia circuit. The reviewing court shall reverse any such finding of the Commission if the State or Federal agency determination involved is supported by substantial evidence.

(c) State authority.—

(1) General rule.—A Federal or State agency having regulatory jurisdiction with respect to the production of natural gas is authorized to make determinations referred to in subsection (a) of this section.

(2) Waiver.—

(A) In general.—Any Federal or State agency may, in whole or in part, waive its authority to make determinations referred to in subsection (a)(1) of this section by entering into an agreement in accordance with subparagraph (B). If such agency executes such a waiver, the Commission shall, consistent with the agreement, make the determinations which would otherwise be made by such Federal or State agency until the earlier of—

(i) the expiration of the period specified in the agreement; or

(ii) the date such agency transmits to the Commission written notice that it termi-

nates such waiver and assumes the authority to make determinations referred to in subsection (a) (1) of this section.

Any waiver, or termination of any waiver, shall not apply to any determination with respect to any petition therefor which is pending before such agency or the Commission (as the case may be) on the date on which such a waiver or revocation is made.

(B) Agreements.—Any waiver under subparagraph (A) may be made only by a written agreement between the Federal or State agency involved and the Commission. Any such agreement shall set forth the terms and conditions applicable to such waiver.

(3) Procedures applicable.—Determinations of a Federal or State agency referred to in subsection (a) (1) of this section shall be made in accordance with the procedures generally applicable to such agency for the making of such determinations or comparable determinations under the provisions of Federal or State law, as the case may be, pursuant to which they exercise their regulatory jurisdiction. The Commission may prescribe the form and content of filings with a Federal or State agency in connection with determinations made under this section.

(4) Judicial review.—Any such determination referred to in subsection (a) (1) of this section made in accordance with procedures described in paragraph (3) shall not be subject to judicial review under any Federal or State law except as provided under subsection (b) of this section.

(d) Effect of determinations.—For purposes of this chapter.—

(1) General rule.—Any final determination referred to in subsection (a) (1) of this section made

by a Federal or State agency (or by the Commission under subsection (c)(2) of this section) which relates to any natural gas and which is no longer subject to review by the Commission under this section or to judicial review shall thereafter be binding with respect to such natural gas. The preceding sentence shall not apply to any final determination—

(A) if in making such determination the Commission or such Federal or State agency relied on any untrue statement of a material fact; or

(B) if there was omitted a statement of material fact necessary in order to make the statements made not misleading, in light of the circumstances under which they were made, to the Federal or State agency in making such final determination or to the Commission in reviewing such determination.

(2) Application of title 18.—Any untrue statement or omission of material fact to a Federal or State agency upon which the Commission relied shall be deemed to be statement or entry under section 1001 of Title 18.

(e) Interim collection of maximum lawful price.—

(1) Collection of section 3319 price.—

(A) General rule.—Effective beginning on the first day of the first month beginning after November 9, 1978, a seller of natural gas which is produced from a new well may, in accordance with subparagraph (B), charge and collect the appropriate maximum lawful price under section 3319 of this title for any first sale of such natural gas.

(B) Requirements.—A seller may charge and make collections under subparagraph (A) only in accordance with the following requirements:

(i) Sworn statement.—Before any such collection is made, the seller shall file with the Commission, and any Federal or State agency having authority to make determinations referred to in subsection (a)(1) of this section, a written sworn statement that such natural gas is produced from a new well and that such seller believes in good faith that such natural gas is eligible under this chapter to be sold at a price not less than the appropriate maximum lawful price under section 3319 of this title.

(ii) Petition for determination.—Within 90 days after November 9, 1978, the seller files a petition to such Federal or State agency for a determination under this section.

(iii) Collection subject to refund.—Any such collection made by the seller pending a determination under this section shall be collected subject to a condition of refund, with interest, in the event it is determined by such Federal or State agency that the applicable maximum lawful price is lower than that provided under section 3319 of this title.

(2) Alternate interim collection authority.—

(A) General rule.—Promptly after November 9, 1978, the Commission shall, by rule or order, provide one or more methods under which a seller of natural gas may, in accordance with requirements established, and for such period as may be prescribed, under such rule or order, charge and collect for any first sale of such natural gas the maximum lawful price under subchapter I of this chapter for which a petition is filed for a determination under this section in any case in

which such price exceeds the appropriate maximum lawful price under section 3319 of this title.

(B) Collection subject to refund.—Any such collection made by the seller pending a determination under this section shall be collected subject to a condition of refund, with interest. Such refund with interest shall be paid, in accordance with the rule under subparagraph (A), unless it is determined under this chapter that the applicable maximum lawful price is equal to or greater than that collected. In addition, such seller shall comply with such requirements as the Commission shall prescribe in the applicable rule or order to provide adequate assurance that funds, to the extent attributable to a price in excess of the appropriate maximum lawful price under subchapter I of this chapter are available in the event of such refund.

(3) Collection after initial determination.—

(A) General rule.—Effective beginning on the date of the notice of a determination under subsection (a) (2) of this section, a seller of natural gas covered by such determination may, in accordance with subparagraph (B), charge and collect the appropriate maximum lawful price applicable under such determination.

(B) Requirements.—A seller may charge and make collections under subparagraph (A) if such collection is subject to conditions prescribed by the Commission to assure refund, with interest, in the event it is determined under this chapter that the applicable lawful price is lower than that provided under section 3319 of this title.

(Pub.L. 95-621, Title V, § 503, Nov. 9, 1978, 92 Stat. 3397.)

§ 3414. Enforcement

(a) General rule.—It shall be unlawful for any person—

(1) to sell natural gas at a first sale price in excess of any applicable maximum lawful price under this chapter; or

(2) to otherwise violate any provision of this chapter or any rule or order under this chapter.

(b) Civil enforcement.—

(1) In general.—Except as provided in paragraphs (2) and (3), whenever it appears to the Commission that any person is engaged or about to engage in any act or practice which constitutes or will constitute a violation of any provision of this chapter, or of any rule or order thereunder, the Commission may bring an action in the District Court of the United States for the District or Columbia or any other appropriate district court of the United States to enjoin such act or practice and to enforce compliance with this chapter, or any rule or order thereunder.

(2) Enforcement of emergency orders.—Whenever it appears to the President that any person has engaged, is engaged, or is about to engage in acts or practices constituting a violation of any order under section 3362 of this title or any order or supplemental order issued under section 3363 of this title, the President may bring a civil action in any appropriate district court of the United States to enjoin such acts or practices.

(3) Enforcement of incremental pricing.—The Secretary, the Commission, or, on the request of the Secretary or the Commission, the Attorney General, may institute a civil action for injunctive or other equitable relief as may be appropriate to assure compliance with the provisions of section 3345 of this

title requiring the passthrough of surcharges paid under section 3344 of this title by any local distribution company with respect to nautral[1] gas delivered to incrementally priced industrial facilities served by such company. Such action may be instituted in any district court of the United States in the State in which such local distribution company conducts business or in the District Court of the United States for the District of Columbia.

(4) Relief available.—In any action under paragraph (1), (2), or (3), the court shall, upon a proper showing, issue a temporary restraining order or preliminary or permanent injunction without bond. In any such action, the court may also issue a mandatory injunction commanding any person to comply with any applicable provision of law, rule, or order, or ordering such other legal or equitable relief as the court determines appropriate, including refund or restitution.

(5) Criminal referral.—The Commission may transmit such evidence as may be available concerning any acts or practices constituting any possible violations of the Federal antitrust laws to the Attorney General who may institute appropriate criminal proceedings.

(6) Civil penalties.—

(A) In general.—Any person who knowingly violates any provision of this chapter, or any provision of any rule or order under this chapter, shall be subject to—

(i) except as provided in clause (ii) a civil penalty, which the Commission may assess, of not more than $5,000 for any one violation; and

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[1] So in original. Probably should be "natural".

(ii) a civil penalty, which the President may assess, of not more than $25,000, in the case of any violation of an order under section 3362 of this title or an order or supplemental order under section 3363 of this title.

(B) Definition of knowing.—For purposes of subparagraph (A), the term "knowing" means the having of—

(i) actual knowledge; or

(ii) the constructive knowledge deemed to be possessed by a reasonable individual who acts under similar circumstances.

(C) Each day separate violation.—For purposes of this paragraph, in the case of a continuing violation, each day of violation shall constitute a separate violation.

(D) Statute of limitations.—No person shall be subject to any civil penalty under this paragraph with respect to any violation occurring more than 3 years before the date on which such person is provided notice of the proposed penalty under subparagraph (E). The preceding sentence shall not apply in any case in which an untrue statement of material fact was made to the Commission or a State or Federal agency by, or acquiesced to by, the violator with respect to the acts or omissions constituting such violation, or if there was omitted a material fact necessary in order to make any statement made by, or acquiesced to by, the violator with respect to such acts or omissions not misleading in light of circumstances under such statement was made.

(E) Assessed by commission.—Before assessing any civil penalty under this paragraph, the Commission shall provide to such person notice

of the proposed penalty. Following receipt of notice of the proposed penalty by such person, the Commission shall, by order, asssess[2] such penalty.

(F) Judicial review.—If the civil penalty has not been paid within 60 calendar days after the assessment order has been made under subparagraps (E), the Commission shall institute an action in the appropriate district court of the United States for an order affirming the assessment of the civil penalty. The court shall have authority to review de novo the law and the facts involved, and shall have jurisdiction to enter a judgment enforcing, modifying, and enforcing as so modified, or setting aside in whole or in part, such assessment.

(c) Criminal penalties.—

(1) Violation of chapter.—Except in the case of violations covered under paragraph (3), any person who knowingly and willfully violates any provision of this chapter shall be subject to—

(A) a fine or not more than $5,000; or

(B) imprisonment for not more than two years; or

(C) such fine and such imprisonment.

(2) Violation of rules or orders generally.—Except in the case of violations covered under paragraph (3), any person who knowingly and willfully violates any rule or order under this chapter (other than an order of the Commission assessing a civil penalty under subsection (b)(4)(E) of this section), shall be subject to a fine of not more than $500 for each violation.

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[2] So in original. Probably should be "assess".

(3) Violations of emergency orders.—Any person who knowingly and willfully violates an order under section 3362 of this title or an order or supplemental order under section 3363 of this title shall be fined not more than $50,000 for each violation.

(4) Each day separate violation.—For purposes of this subsection, each day of violation shall constitute a separate violation.

(5) Definition of knowingly.—For purposes of this subsection, the term "knowingly"; when used with respect to any act or omission by any person, means such person—

(A) had actual knowledge; or

(B) had constructive knowledge deemed to be possessed by a reasonable individual who acts under similar circumstances.

(Pub.L. 95-621, Title V, § 504, Nov. 9, 1978, 92 Stat. 3401.)

SUBCHAPTER VI—COORDINATION WITH NATURAL GAS ACT; MISCELLANEOUS PROVISIONS

§ 3431. Coordination with Natural Gas Act

(a) Jurisdiction of Commission under Natural Gas Act.—

(1) Sales.—

(A) Natural gas not committed or dedicated. —For purposes of section 1(b) of the Natural Gas Act, effective on the first day of the first month beginning after November 9, 1978, the provisions of the Natural Gas Act and the jurisdiction of the Commission under such Act shall not apply to natural gas which was not committed or dedicated to interstate commerce as of November 8, 1978, solely by reason of any first sale of such natural gas.

(B) Committed or dedicated natural gas.—Effective beginning on the first day of the first month beginning after November 9, 1978, for purposes of section 1(b) of the Natural Gas Act, the provisions of such Act and the jurisdiction of the Commission under such Act shall not apply solely by reason of any first sale of natural gas which is committed or dedicated to interstate commerce as of November 8, 1978, and which is—

(i) high-cost natural gas (as defined in section 3317(c)(1), (2), (3), or (4) of this title);

(ii) new natural gas (as defined in section 3312(c) of this title); or

(iii) natural gas produced from any new, onshore production well (as defined in section 3313(c) of this title).

(C) Authorized sales or assignments.—For purposes of section 1(b) of the Natural Gas Act, the provisions of the Natural Gas Act and the jurisdiction of the Commission under such Act shall not apply by reason of any sale of natural gas—

(i) authorized under section 3362(a) or 3371(b) of this title; or

(ii) pursuant to any assigned[1] authorized under section 3372(a) of this title.

(D) Natural-gas company.—For purposes of the Natural Gas Act, the term "natural-gas company" (as defined in section 2(6) of such Act) shall not include any person by reason of, or with respect to, any sale of natural gas if the provisions of the Natural Gas Act and the jurisdiction of the Commission do not apply to such sale solely by reason of subparagraph (A), (B), or (C) of this paragraph.

(E) Alaskan natural gas.—Subparagraph (B)(ii) and (iii) shall not apply with respect to natural gas produced from the Prudhoe Bay unit of Alaska and transported through the transportation system approved under the Alaska Natural Gas Transportation Act of 1976.

(2) Transportation.—

(A) Jurisdiction of the Commission.—For purposes of section 1(b) of the Natural Gas Act the provisions of such Act and the jurisdiction of the Commission under such Act shall not apply to any transportation in interstate commerce of natural gas if such transportation is—

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[1] So in original. Probably should be "assignment".

(i) pursuant to any order under section 3362(c) or section 3363(b), (c), (d), or (h) of this title; or

(ii) authorized by the Commission under section 3371(a) of this title.

(B) Natural-gas company.—For purposes of the Natural Gas Act, the term "natural-gas company" (as defined in section 2(6) of such Act) shall not include any person by reason of, or with respect to, any transportation of natural gas if the provisions of the Natural Gas Act and the jurisdiction of the Commission under the Natural Gas Act do not apply to such transportation by reason of subparagraph (A) of this paragraph.

(b) Charges deemed just and reasonable.—

(1) Sales.—

(A) First sales.—Subject to paragraph (4), for purposes of sections 4 and 5 of the Natural Gas Act, any amount paid in any first sale of natural gas shall be deemed to be just and reasonable if—

(i) such amount does not exceed the applicable maximum lawful price established under subchapter I of this chapter; or

(ii) there is no applicable maximum lawful price solely by reason of the elimination of price controls pursuant to part B of subchapter I of this chapter.

(B) Emergency sales.—For purposes of sections 4 and 5 of the Natural Gas Act, any amount paid in any sale authorized under section 3362(a) of this title shall be deemed to be just and reasonable if such amount does not exceed the fair and equitable price established under such section and applicable to such sale.

(C) Sales by intrastate pipelines.—For purposes of sections 4 and 5 of the Natural Gas Act, any amount paid in any sale authorized by the Commission under section 3371(b) of this title shall be deemed to be just and reasonable if such amount does not exceed the fair and equitable price established by the Commission and applicable to such sale.

(D) Assignments.—For purposes of sections 4 and 5 of the Natural Gas Act, any amount paid pursuant to the terms of any contract with respect to that portion of which the Commission has authorized an assignment authorized under section 3372(a) of this title shall be deemed to be just and reasonable if such amount does not exceed the applicable maximum lawful price established under subchapter I of this chapter.

(E) Affiliated entities limitation.—For purposes of paragraph (1), in the case of any first sale between any interstate pipeline and any affiliate of such pipeline, any amount paid in any first sale shall be deemed to be just and reasonable if, in addition to satisfying the requirements of such paragraph, such amount does not exceed the amount paid in comparable first sales between persons not affiliated with such interstate pipeline.

(2) Other charges.—

(A) Allocation.—For purposes of sections 4 and 5 of the Natural Gas Act, any amount paid by any interstate pipeline for transportation, storage, delivery or other services provided pursuant to any order under section 3363(b), (c), or (d) of this title shall be deemed to be just and reasonable if such amount is prescribed by the President under Section 3363(h)(1) of this title.

(B) Transportation.—For purposes of sections 4 and 5 of the Natural Gas Act, any amount paid by any interstate pipeline for any transportation authorized by the Commission under section 3371(a) of this title shall be deemed to be just and reasonable if such amount does not exceed that approved by the Commission under such section.

(c) Guaranteed passthrough.—

(1) Certificate may not be denied based upon price.—The Commission may not deny, or condition the grant of, any certificate under section 7 of the Natural Gas Act based upon the amount paid in any sale of natural gas, if such amount is deemed to be just and reasonable under subsection (b) of this section.

(2) Recovery of just and reasonable prices paid.—For purposes of sections 4 and 5 of the Natural Gas Act, the Commission may not deny any interstate pipeline recovery of any amount paid with respect to any purchase of natural gas if—

(A) under subsection (b) of this section, such amount is deemed to be just and reasonable for purposes of sections 4 and 5 of such Act, and

(B) such recovery is not inconsistent with any requirement of any rule under section 3341 of this title (including any amendment under section 3342 of this title),

except to the extent the Commission determines that the amount paid was excessive due to fraud, abuse, or similar grounds.

(Pub.L. 95-621, Title VI, § 601, Nov. 9, 1978, 92 Stat. 3409.)

APPENDIX D

FEDERAL ENERGY REGULATORY COMMISSIONS REGULATIONS

CODE OF FEDERAL REGULATIONS TITLE 18

PART 271—CEILING PRICES

Subpart A—Summary Tables and Calculations

§ 271.101 Ceiling prices for certain categories of natural gas.

(a) The maximum lawful price for natural gas subject to Subparts B, C, G, H, and I of this part, and certain natural gas subject to Subpart F thereof, are specified in Table I. The maximum lawful prices for certain categories of natural gas subject to Subpart D of this part are specified in Table II.

[Tables I and II Omitted in Printing]

§ 271.305 Special rule applicable to existing proration units.

(a) *Applicability.* (1) This section applies only to a jurisdictional agency determination with respect to a new well which is within a State law proration unit:

(i) Which was in existence at the time the surface drilling of such well began;

(ii) Which was applicable to the reservoir from which natural gas from such well is produced; and

(iii) Which applied to a well:

(A) Which produced natural gas in commercial quantities; or

(B) The surface drilling of which was begun before February 19, 1977, and which was thereafter capable of producing natural gas in commercial quantities.

(2) For purposes of this paragraph, State law proration unit means a proration unit, drilling unit or similar unit expressly designated in accordance with State law or Federal law (other than the NGPA).

(b) *Wells spudded on or after February 19, 1977.*

(1) In order for natural gas from a well to which this section applies to qualify for the maximum lawful price under this subpart, the jurisdictional agency must explicitly find that the well is necessary to effectively and efficiently drain a portion of the reservoir covered by the proration unit which cannot be effectively and efficiently drained by any existing well within the proration unit. This explicit finding must be based on appropriate geological and engineering data and such data must be included in the notice of determination submitted to the Commission.

(2) [Reserved]

(c) *Notice of finding.* If the jurisdictional agency makes a finding under paragraph (b)(1) of this section, it shall notify the Commission of such a determination in accordance with § 274.104.

(d) *Rebuttable presumption for certain wells drilled on existing proration units.* For the purposes of section 103(c)(3)(C) of the NGPA and paragraph (a)(1)(iii) of this section, if a well has been plugged and abandoned prior to January 1, 1970 and has not produced natural gas on or after that date, a rebuttable presumption is created that the well has not produced and is not capable of producing natural gas in commercial quantities.

APPENDIX E

[61,476]

[¶61,207]

Docket No. GP84-23-000

STOWERS OIL & GAS COMPANY, *et al.*

ORDER INITIATING SHOW CAUSE PROCEEDING AND PRESCRIBING EXPEDITED PROCEDURES

(Issued February 15, 1985)

Before Commissioners: Raymond J. O'Connor, Chairman; Georgiana Sheldon, J. David Hughes, A. G. Sousa and Oliver G. Richard III.

I.

A preliminary investigation has been conducted by the Enforcement Division of the Office of the General Counsel under the Commission's Rules Relating to Investigations, 18 C.F.R. Part 1b (1983), into certain sales of natural gas produced from the West Panhandle Field, Carson and Gray Counties, Texas. As a result of the preliminary investigation, information has been reported to the Commission alleging that certain oil well operators may have engaged and may be engaging in acts and practices which violate the Natural Gas Act ("NGA"), 15 U.S.C. § 717, *et seq.* (1982), the Natural Gas Policy Act of 1978 ("NGPA"), 15 U.S.C. § 3301, *et seq.* (1982), and the Commission's regulations thereunder.

Thirty-seven oil well operators are named as respondents in this proceeding. These operators, the identity and location of the wells which they operate, and other information is set forth in the table annexed hereto as Appendix A, which is incorporated herein and made a part hereof. The facts alleged in Section II of this order describe the acts and [61,477] practices which are the subject of this proceeding.

II.

1. On or about July 1, 1954, Dorchester Corporation, a parent corporation of Dorchester Gas Producing Company ("Dorchester"), acquired by conveyance from Nalam Corporation the interest in gas produced from all formations lying in whole or in part above sea level on certain acreage in the West Panhandle Field, Carson and Gray Counties, Texas (the "subject acreage"). Dorchester did not acquire any interest in oil, nor any interest in gas formations lying wholly below sea level.

2. By contract dated July 1, 1952 (the "1952 Contract"), Dorchester's predecessors in interest had dedicated to Northern Natural Gas Company ("Northern"), an interstate natural gas pipeline company, "all of its gas rights in the gas lands and leases covering the [subject] acreage . . . together with all wells now drilled or hereafter to be drilled on such acreage . . . . ," as that acreage is described in the Exhibits to the 1952 Contract.

3. On November 26, 1954, Dorchester filed with the Commission an application in Docket No. G-5925 for a certificate of public convenience and necessity pursuant to Section 7(c) of the NGA covering sales to Northern under the 1952 Contract, which was incorporated by reference into the application.

4. By order issued February 6, 1956 in Docket No. G-4568, *et al.*, the Commission issued a certificate of public convenience and necessity to Dorchester covering sales to Northern under the 1952 Contract, as more fully described in the certificate application.

5. Dorchester accepted the certificate of public convenience and necessity and continued sales to Northern of natural gas produced from the subject acreage.

6. Dorchester presently operates numerous gas wells on the subject acreage, of which 36 are primarily affected by the acts and practices which are the subject of this

order. All gas produced from these 36 gas wells is sold to Northern at the applicable maximum lawful price under the NGPA.

7. Each of these 36 affected gas wells, which are also identified on Appendix A, has been assigned a specific "proration unit" by the State of Texas for gas allocation purposes. For all but six such gas wells, the assigned proration units each consist of 640 acres.

8. In most cases, the boundaries of the proration units assigned to these 36 Dorchester gas wells are coextensive with the boundaries of survey sections established by original railroad surveys. These survey sections are typically identified by Block and Section number with in a particular survey.[1] In some cases, however, the proration unit assigned to a particular Dorchester gas well is not coextensive with the boundaries of a particular survey section, and may extend into other adjacent survey sections.

9. The proration units assigned to the 36 Dorchester gas wells are located in the following Blocks and Sections, all of which are within the areal limits of the acreage dedicated under the 1952 Contract by Dorchester to Northern: Block B-2, Sections 113, 114, 115, 117, 126, 127, 128, 144, 153, 182, 183, 206, 208, 209, 210, 211, 239, 241, 242, and 243; Block 3, Sections 108, 109, 133, 134, 155, 156, 157, 158, 176, 177, 182, 184, 202, and 204; Block 4, Sections 1, 2, 16, 21, 22, and 46; and Block 7, Sections 1, 6, 7, 16, 22, 23, and 69.

10. The 36 Dorchester gas wells were completed between 1934 and 1949 into the brown dolomite formation (or stratum), and from the date of their completion to the present, each Dorchester gas well has produced from the brown dolomite formation only natural gas, and no crude oil or condensate.

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[1] In this order, the designations of the I & GN Railroad survey are used to locate individual wells by Block and Section number.

11. The brown dolomite formation is one of four separate strata, and is the primary gas-bearing formation, within the West Panhandle Field.

12. Primarily between 1980 and the present,[2] each of the respondents drilled or caused to be drilled one or more oil wells within the areal limits of the proration units described in paragraph 9, above.

13. Each of these oil wells was initially completed in the granite wash formation (or stratum), which lies below the brown dolomite formation.

14. Prior to Dorchester's acquisition of its gas rights in the leases comprising the subject acreage, the original mineral interest owners assigned to a third party all right, title and interest in and to the same oil and gas mineral leases "insofar as said leases and leasehold estates cover the oil and oil rights only in and to the producing horizons thereunder . . . ." The assignment expressly provides that it does not cover or include any right, title or interest with respect to the gas or gas rights in, to and under said leaseholds.

15. Each of the respondents acquired an interest in oil rights in its respective portion of the subject acreage either by assignment from the successors in interest to the original mineral interest owners or, more commonly, by execution of a farmout agreement with the successors in interest to the original mineral interest owners.

[61,478] 16. The instruments of assignment typically are simple conveyances which make reference to an executed farmout agreement, and the assignment is made "in strict accordance" with the terms and provisions of the farmout agreement.

17. The typical farmout agreement states:

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[2] The date on which each oil well was completed is set forth in Appendix A.

It is expressly provided that this Farmout Agreement does not cover or apply to dry gas rights in and under the lands described on Exhibit "A" and that Farmees shall set and cement casing in all wells drilled hereunder in such a manner as to prevent gas well gas from entering the oil zones. In no event shall any dry gas produced from gas zones be produced with the oil or casinghead gas produced by Farmees.

18. Each of the respondents identified in Appendix A of this order has the right to produce and sell oil from its respective portion of the subject acreage.

19. Dorchester has the right to produce and sell dry gas from the subject acreage.

20. All dry gas produced from the subject acreage is gas which is "committed or dedicated to interstate commerce" under NGPA Section 2(18)(A)(ii), 15 U.S.C. § 3301(18)(A)(ii) (1982).

21. Each of the respondents identified in Appendix A may have the right to produce and sell casinghead gas from its respective portion of the subject acreage.[3]

22. Even if each of the respondents identified in Appendix A of this order has the right to produce and sell casinghead gas from its respective portion of the subject acreage, and even if casinghead gas were not committed or dedicated to interstate commerce, none of the respondents has the right to produce and sell dry gas from its respective portion of the subject acreage.

Apparent Violations of NGA Section 7(b)

23. "Dry gas" means gas produced from a stratum that does not produce oil. Tex. [Nat. Res.] Code Ann. § 86.002(7) (Vernon 1978).

[3] The question of title to casinghead gas is being litigated in Texas state court, and is not in issue in this proceeding.

24. "Casinghead gas" means any gas or vapor indigenous to an oil stratum and produced from the stratum with oil. Tex. [Nat. Res.] Code Ann. § 86.002(10) (Vernon 1978).

25. Section 86.097 of the Texas Natural Resources Code ("Code") provides that "no person in possession of or operating an oil well may produce from the oil well gas found in a horizon productive of gas only." Tex. [Nat. Res.] Code Ann. § 86.097 (Vernon 1978).

26. The respective operator of each of the oil wells identified in Appendix A has perforated the well bore or has caused the well bore to be perforated in the brown dolomite stratum at or near the level of the producing interval of the Dorchester gas well within whose proration unit each such oil well is situated.

27. In most cases, the perforations of the well bore in the brown dolomite stratum were made after each oil well was initially completed in the granite wash stratum, and such additional up-hole perforations (or completion locations) were not reported to the Texas Railroad Commission.

28. Each of the oil wells identified in Appendix A of this order has been completed so as to cause natural gas from the brown dolomite stratum to be produced.

29. The brown dolomite stratum is productive only of dry gas at the level at which the operators of each of the oil wells identified in Appendix A have perforated or have caused the perforation of such oil wells.

30. By virtue of the production of dry gas from the brown dolomite stratum, the operators of the oil wells identified in Appendix A have drained approximately 8.6 Bcf of gas reserves dedicated by Dorchester to interstate commerce.

31. Section 7(b) of the NGA, 15 U.S.C. § 717f(b) (1982), provides:

No natural-gas company shall abandon all or any portion of its facilities subject to the jurisdiction of the Commission, or any service rendered by means of such facilities, without permission and approval of the Commission first had and obtained, after due hearing, and a finding by the Commission that the available supply of natural gas is depleted to the extent that the continuance of service is unwarranted, or that the present or future public convenience or necessity permit such abandonment.

32. Each of the respondents identified in Appendix A of this order, with the exception of Tonya Starbuck, K. A. Roberts, and V. T. Stowers, d/b/a Komanche Oil & Gas, L. R. Spradling and V. T. Stowers, d/b/a Stowers Oil & Gas Co., and J. B. Watkins, has produced and sold, is producing and selling, and is about to produce and sell in intrastate commerce [4] natural gas which has been dedicated to interstate commerce, thereby abandoning service subject to the jurisdiction of the Commission without the Commission's prior permission and approval pursuant to NGA Section 7(b), 15 U.S.C. § 717f(b).

33. Each of the respondents identified in Appendix A of this order, with the exception of Tonya Starbuck, K. A. Roberts, and V. T. Stowers, d/b/a Komanche Oil & Gas, L. R. Spradling and V. T. Stowers, d/b/a Stowers Oil & Gas Co., and J. B. Watkins, has failed to file [61,479] an application for abandonment, by which such prior permission and approval must be sought with respect to such abandonment under the Commission's regulations at 18 C.F.R. § 157.30 (1983).

34. Each of the respondents identified in Appendix A of this order, with the exception of Tonya Starbuck, K. A.

[4] The intrastate purchasers are identified in Appendix A; gas produced by oil wells operated by Tonya Starbuck, K. A. Roberts, and V. T. Stowers, d/b/a Komanche Oil & Gas, L. R. Spradling and V. T. Stowers, d/b/a Stowers Oil & Gas Co., and J. B. Watkins is sold exclusively to Northern, the dedicated purchaser.

Roberts, and V. T. Stowers, d/b/a Komanche Oil & Gas, L. R. Spradling and V. T. Stowers, d/b/a Stowers Oil & Gas Co., and J. B. Watkins, appears to have violated, appears to be violating, and appears to be about to violate Section 7(b) of the NGA, 15 U.S.C. § 717f(b), and the Commission's regulations thereunder, 18 C.F.R. § 157.30.

Apparent Violations of NGPA Section 504

35. Dry gas is considered to be "natural gas" under Section 2(1) of the NGPA, 15 U.S.C. § 3301(1) (1982).

36. Section 2(21)(A) of the NGPA, 15 U.S.C. § 3301 (21)(A) (1982), defines a "first sale" of natural gas as, *inter alia,* any sale of any volume of natural gas to any interstate pipeline or intrastate pipeline.

37. At all relevant times, the sales by each of the respondents of all natural gas produced from the oil wells identified in Appendix A of this order were "first sales" within the meaning of NGPA Section 2(21)(A).

38. Section 104 of the NGPA, 15 U.S.C. § 3314 (1982), establishes, pursuant to a pricing formula, the maximum lawful prices at which natural gas "committed or dedicated to interstate commerce" as of November 8, 1978, and for which a just and reasonable rate under the NGA was in effect on that date, may be sold in any "first sale" of such natural gas.

39. Dry gas produced and sold from the subject acreage was natural gas "committed or dedicated to interstate commerce" as of November 8, 1978, as defined in Section 2(18)(A)(ii) of the NGPA, 15 U.S.C. § 3301 (18)(A)(ii).

40. A just and reasonable rate under the NGA was in effect on November 8, 1978, for dry gas produced from the subject acreage.

41. All dry gas produced from the subject acreage must be sold at the maximum lawful price established by

Section 104 of the NGPA, 15 U.S.C. § 3314, and the Commission's regulations thereunder, 18 C.F.R. §§ 271.101 and 271.402 (1983), in any first sale, except to the extent that a particular well producing such dry gas has qualified for pricing under some other section of NGPA Title I.

42. A "proration unit" as defined in NGPA Section 2(8), 15 U.S.C. § 3301(2)(8) (1982), is that portion of a reservoir, as designated by the agency having regulatory jurisdiction with respect to production from such reservoir, which will be effectively and efficiently drained by a single well.

43. Each of the respondents identified in Appendix A of this order, with the exception of the Harlow Corporation, Walker Operating Corporation, and J. B. Watkins, has filed an application for a well category determination under Section 103 of the NGPA, 15 U.S.C. § 3313 (1982) (new onshore production wells), for all or some of the oil wells identified in Appendix A operated by such respondent.

44. The well category determination applications filed by the respondents identified in paragraph 43, with the exception of the applications for determination filed by Dahalo Lease Corporation and Lear Oil & Gas, Inc., have been affimatively determined by the State jurisdictional agency, and those affirmative Section 103 determinations have become final.

45. None of the respondents whose oil wells have received final, affirmative NGPA Section 103 well category determinations in the dockets identified in Appendix A of this order has obtained pursuant to 18 C.F.R. § 271.305 (1983) an explicit finding from the Texas Railroad Commission that the well for which a determination was sought is necessary to effectively and efficiently drain the brown dolomite formation, which is the portion of the reservoir drained by, and covered by a proration unit assigned to, an existing Dorchester gas well.

46. Each of the final, affirmative NGPA Section 103 well category determinations received by the respondents identified in Appendix A of this order relates *only* to the sale of casinghead gas, and not to the sale of dry gas, produced from each such oil well.

47. Each of the respondents identified in Appendix A of this order, with the exception of the Harlow Corporation, Walker Operating Corporation, and J. B. Watkins, has charged and collected, is charging and collecting, and is about to charge and collect maximum lawful prices under Section 103 of the NGPA, 15 U.S.C. § 3313, for dry gas produced from one or more of the oil wells which each respectively operates.

48. Dahalo Lease Corporation; the Harlow Corporation; Kim Petroleum Co., Inc.; Tonya Starbuck, K. A. Roberts, and V. T. Stowers, d/b/a Komanche Oil & Gas; Meyer Farms Inc.; Sharon Caldwell Ward, d/b/a Sharon Lease Oil Co.; Walker Operating Corporation, J. B. Watkins; and Wy-Vel Corp. have charged and collected, are charging and collecting, and are about to charge and collect maximum [61,480] lawful prices under Section 109 of the NGPA, 15 U.S.C. § 3319 (1982), for dry gas produced from one or more of the oil wells which each respectively operates.

49. Each of the respondents identified in Appendix A of this order has charged and collected, is charging and collecting, and is about to charge and collect a rate for a first sale of dry gas produced from one or more oil wells which each respectively operates in excess of the applicable maximum lawful price under Section 104 of the NGPA and the Commission's regulations thereunder, 18 C.F.R. §§ 271.101 and 271.402.

50. Each of the respondents identified in Appendix A of this order appears to have violated, appears to be violating, and appears to be about to violate Section 504(a)(1) of the NGPA, 15 U.S.C. § 3414(a)(1) (1982) and

the Commission's regulations thereunder, 18 C.F.R. §§ 271.101 anud 271.402.

III.

A. The Commission neither makes findings of fact nor reaches conclusions of law with regard to the respondents' alleged acts and practices. However, the allegations set forth in Section II of this order raise the possibility that inexpensive dedicated gas reserves have been and are being irrevocably drained from the interstate market and sold at unlawfully high rates. Because of the seriousness of these allegations, the Commission finds it appropriate that this matter be resolved expeditiously. Therefore, in setting this matter for hearing before an administrative law judge, we are establishing procedures to promote a speedy, efficient and fair resolution consistent with our responsibilities to vigorously enforce the provisions of the NGA and NGPA.

To this end, the proceeding shall be conducted in two phases. The first phase will resolve the issue of the respondents' alleged violations of law. If the alleged acts and practices of the respondents are determined to constitute violations of the NGA, the NGPA, and/or the Commission's regulations thereunder, then there shall be a second phase of the proceeding. The second phase will resolve the issue of the extent of the violations and the appropriate monetary remedies to be imposed by the Commission in connection therewith, including, but not limited to, requiring disgorgement by the respondents of any revenues unlawfully collected. However, if, during the first phase, it is determined that violations of the NGA or NGPA are on-going, then prior to the commencement of the second phase, it shall also be determined whether an order prohibiting the respondents from violating the NGA and/or the NGPA is appropriate.

The second phase will be held in abeyance pending the resolution of the first phase. We believe that a phasing of the proceeding will speed up the decisional process by

postponing consideration of, and the need to gather and adduce evidence concerning, such remedial issues as the total volume of gas diverted and the revenues collected in connection therewith. These matters need not be addressed until after it is determined whether the alleged acts and practices of the respondents violate the NGA, the NGPA, and/or the Commission's regulations thereunder.

The issues to be addressed in the hearing and briefs in the first phase of this proceeding are:

(1) Whether the respondents have produced and sold, are producing and selling, or are about to produce and sell in intrastate commerce natural gas which is committed or dedicated to interstate commerce without having sought or obtained the prior permission and approval of the Commission pursuant to Section 7(b) of the NGA?

(2) Whether the respondents have charged and collected, are charging and collecting, or are about to charge and collect a price in connection with any first sale of natural gas which is committed or dedicated to interstate commerce which is in excess of the applicable maximum lawful price under Section 104 of the NGPA?

The Commission intends to issue its decision in this matter at the earliest possible date.

B. By separate order today [26 FERC ¶ 61,208], we are dismissing the petitions for declaratory order filed by Stowers Oil & Gas Company, *et al.*, and by Northern Natural Gas Company, division of InterNorth, Inc.,[5] both of which relate to the acts and practices which are the subject of this proceeding. The dockets in which those petitions were filed are terminated by that order. Petitioners who intervened in those dockets must intervene

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[5] Docket No. GP84-5-000, filed October 26, 1983 and Docket No. GP84-7-000, filed October 28, 1983, respectively.

in this docket if they wish to become parties in this proceeding.

C. We recognize that the acts and practices which are the subject of this proceeding may not be confined to acreage which has been dedicated to interstate commerce by Dorchester.[6] To the extent that similar acts and practices occurring on other dedicated acreage involve questions of law which are in comon with those to be addressed in this proceeding, the Commission invites those who may be affected by them to [61,481] intervene in this proceeding for the limited purpose of briefing those legal questions. However, the Commission would view with disfavor any attempt to expand the scope of this proceeding to include facts relating to similar acts and practices which may be occurring on acreage other than Dorchester's. The Enforcement Division has been directed to continue its preliminary investigation of such similar acts and practices.

The Commission finds:

(1) Good cause exists for requiring, and the public interest in administering the NGA and NGPA demands, that each respondent identified in Appendix A show cause why that respondent should not be found to have violated Section 7(b) of the NGA, Section 504(a)(1) of the NGPA, and the Commission's regulations thereunder as a result of the acts and practices which are the subject of this order. Each respondent shall show cause why the Commission should not order any or all appropriate remedies including, but not limited to, prohibiting that respondent from engaging in acts and practices which con-

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[6] A petition for declaratory order alleging that similar acts and practices are occurring on its dedicated acreage in the West Panhandle Field has been filed by Colorado Interstate Gas Company ("CIG") in Docket No. GP84-8-000. This petition shall be held in abeyance, pending the conclusion by the Enforcement Division of its preliminary investigation of CIG's allegations.

stitute violations of the NGA, prohibiting that respondent from charging and collecting rates for sales of natural gas from the subject oil wells in excess of the applicable maximum lawful price for such sales under the NGPA, and requiring that respondent to disgorge any revenues unlawfully collected in connection with such sales, together with interest computed under 18 C.F.R. § 154.102(c).

(2) In view of the fact that the allegations set forth in Section II of this order, if true, raise the possibility that inexpensive gas reserves have been and are being irretrievably drained from the interstate market and sold at unlawfully high rates, there is good cause to waive any provision of the Commission's Rules of Practice and Procedure which may be inconsistent with the expedited procedures prescribed by this order, which procedures the Commission has determined to be appropriate in this matter.

The Commission orders:

(A) Pursuant to Rule 209 of the Commission's Rules, 18 C.F.R. § 385.209, a show cause proceeding is hereby initiated against the respondents identified in Appendix A of this order.

(B) Each respondent shall show cause why that respondent should not be found to have violated Section 7(b) of the NGA, Section 504(a)(1) of the NGPA, and the Commission's regulations thereunder as a result of the acts and practices alleged in Section II of this order. Each respondent shall show cause why the Commission should not order any or all appropriate remedies, including but not limited to, prohibiting that respondent from engaging in acts and practices which constitute violations of the NGA, prohibiting that respondent from charging and collecting rates for sales of natural gas from the subject oil wells in excess of the applicable maximum lawful price for such sales under the NGPA, and requir-

ing that respondent to disgorge any revenues unlawfully collected in connection with such sales, together with interest computed under 18 C.F.R. § 154.102(c).

(C) Each respondent's answer to this order shall be filed pursuant to Rule 213 of the Commission's Rules, 18 C.F.R. § 385.213, in writing and under oath, on or before 15 days after the date of this order. Accordingly, each respondent shall admit or deny, specifically and in detail, each allegation set forth in Section II of this order as it pertains to each such respondent, and each respondent shall set forth every defense relied on.

(D) Pursuant to Sections 4, 7, 15 and 16 of the NGA, Section 501 of the NGPA, and Rule 601 of the Commission's Rules, 18 C.F.R. § 385.601, a prehearing conference shall be convened in this proceeding in a hearing room of the Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, within 20 days after the date of this order at 10:00 a.m. Eastern Daylight Time. Each respondent shall be fully prepared, as set forth in Rule 601(b) of the Commission's Rules, 18 C.F.R. § 385.601(b), to discuss any and all matters to be considered at the conference.

(E) A Presiding Administrative Law Judge, to be designated by the Chief Administrative Law Judge, shall preside at the prehearing conference in this proceeding, with authority to establish and change procedural dates and to rule on motions, all as provided for in the Commission's Rules, 18 C.F.R. Part 385.

(F) This proceeding shall be phased. The first phase shall resolve the issue of the respondents' alleged violations of law. If the alleged acts and practices of the respondents are determined to constitute violations of the NGA, NGPA and/or the Commission's regulations thereunder, then there shall be a second phase of the proceeding to determine the appropriate monetary remedies to be imposed by the Commission in connection therewith. How-

ever, if during the first phase of the proceeding it is determined that violations of the NGA or NGPA are ongoing, then prior to the commencement of the second phase, it shall also be determined whether an order [61,482] prohibiting the respondents from violating the NGA and/or NGPA is appropriate.

(G) The presiding administrative law judge shall establish an expedited hearing date for a full hearing on the merits. The judge shall conduct all hearings pursuant to Rule 501, *et seq.*, of the Commission's Rules, 18 C.F.R. § 385.501, *et seq.*, and has all authority delegated by Rule 504 of the Commission's Rules, 18 C.F.R. § 385. 504.

(H) Pursuant to Rule 709 of the Commission's Rules, 18 C.F.R. § 385.709, the presiding administrative law judge shall not render an initial decision. Instead, after completion of the expedited hearing, the presiding administrative law judge shall, pursuant to 5 U.S.C. § 557(b) and Rule 709 of the Commission's Rules, 18 C.F.R. § 385.709, promptly render a recommended decision and certify the entire record to the Commission for decision. Prior to rendering a recommended decision, and consistent with our directive that this matter be resolved expeditiously, the presiding administrative law judge shall permit parties a reasonable opportunity to submit for consideration, either in writing or orally, as is determined to be appropriate in the circumstances, proposed findings and conclusions and the reasons supporting such findings and conclusions. There being no initial decision, no briefs on exceptions and no briefs opposing exceptions shall be filed with the Commission under Rule 711 of the Commission's Rules, 18 C.F.R. § 385.711.

(I) Since many of the facts pertinent to the issues in this proceeding are within the particular knowledge of the respondents and/or their employees and agents, Enforcement Staff shall be permitted liberal discovery in

this proceeding. To further promote the expeditious resolution of this proceeding, the Commission supplements its discovery rules by providing that a participant or party may serve upon any other participant or party a written request for the admission, for the purposes of this proceeding only, of the truth of any matters that relate to statements or opinions of fact or of the application of law to fact, including the genuineness of any documents described in the request. Each matter of which an admission is requested shall be separately set forth, and the matter is admitted unless, within 30 days after service of the request, or within such shorter or longer time as the presiding administrative law judge may allow, the participant or party to whom the request is directed serves upon the participant or party requesting the admission a written answer or objection addressed to the matter, signed by the participant or party or by its attorney.

(J) Each respondent shall, within 30 days after the date of this order, produce with respect to *each* of the oil wells identified in Appendix A operated by such respondent, the following information and/or documents to the presiding administrative law judge, for inspection and reproduction by Enforcement Staff:

(1) Copies of all electrical, acoustical, radio-active or other logs run on such wells, including, but not limited to, porosity logs (FDC-CNL and Gamma Ray neutron), sonic logs and resistivity logs;

(2) Copies of all computer logs run on such wells, including, but not limited to, Cyberlook;

(3) Copies of cement bond logs and perforating depth control logs run on such wells; and

(4) Copies of work-over records, including service tickets by logging and/or perforating companies.

(K) If the presiding administrative law judge determines that there is evidence of sales of natural gas pro-

duced by oil wells on Dorchester's subject acreage in the West Panhandle Field other than those identified in Appendix A of this order or operated by entities other than those identified in Appendix A of this order, the presiding administrative law judge may expand the scope of this proceeding to include such entities as respondents and to place such sales at issue in this proceeding.

(L) Pursuant to Rule 101(e) of the Commission's Rules, 18 C.F.R. § 385.101(e), for good cause, the Commission hereby waives any provision of the Commission's Rules which may be inconsistent with the procedures prescribed by this order for this proceeding.

(M) Petitions for intervention shall be filed no later than 15 days after the date of this order. Any person who has filed a petition to intervene in Docket No. GP84-5-000 or GP84-7-000 must file a petition to intervene in this proceeding to be considered a party to this proceeding. Any person who has filed a petition to intervene in Docket No. GP84-8-000 must also file a petition to intervene in this proceeding, but participation in this proceeding shall be for the limited purpose of briefing common questions of law.

[Appendix A Omitted in Printing]

APPENDIX F

[¶ 63,048]

Docket No. GP84-23-000

STOWERS OIL & GAS COMPANY, *et al.*

Motion to Compel Denied

(Issued April 20, 1984)

Brenda P. Murray, Administrative Law Judge.

On April 12, 1984, Anadarko Production Company (Anadarko) and Pan Eastern Exploration Company (Pan Eastern) filed a motion to compel the Stowers Oil & Gas Company, *et al.* (Producer Group) to answer Interrogatories, Request for Production and Inspection, and Request for Admission served on March 9, 1984. Movants claim their discovery requests are modelled on the Producer Group's discovery requests to Staff. They argue they are relevant to show that the Producer Group's "Railroad Commission defenses" are flawed because:

1. The well operators, not the Texas Railroad Commission, classified the wells,

2. The Producer Group operators' oil well classifications are based on fraud,

3. The Producer Group operators' classification of most of their gas production as casinghead gas is doubly fraudulent, and

4. The Producer Group operators' well classification filings, proration unit filings and NGPA well eligibility filings omitted material facts and are therefore void.

The Producer Group's answer contends that the information sought is not relevant because:

1. This Commission has held in abeyance Docket No. GP84-8-000 which concerned whether conversion of a portion of gas production into liquids amounted to an unlawful diversion of natural gas.

2. The Commission's Office of Enforcement, in a Prehearing Conference Memorandum, March 6, 1984, at page 9 states that:

> Also not in issue in this proceeding are the acts and practices of certain respondents involving the use of refrigeration units to extract natural gas liquids ("NGLs") from the gas produced by their oil wells. The question of the propriety of the counting of the extracted NGLs as crude oil for purposes of computing Gas-Oil Ratios is the subject of a proceeding presently pending before the TRC. Very simply, these acts and practices are not material to the existence of the violations of federal law alleged in the Show Cause Order, although they may significantly affect the magnitude of these alleged violations and may prove to be of interest in this proceeding.

3. The Commission's Show Cause Order, 26 FERC ¶ 61,207, footnote 3, states: "The question of title to casinghead gas is being litigated in Texas state court, and not in issue in this proceeding." Enforcement Staff's Prehearing Conference Memorandum noted this fact and commented that resolution of that state court action can not be dispositive of the allegations of violations of federal law contained in the Show Cause order.

4. Anadarko and Pan Eastern's requests are duplicative of Enforcement Staff's discovery requests.

Findings

The motion to compel is denied in major part for several reasons. First, several requests for admissions, for

example number 8, and interrogatories, for example number 24, appear argumentative. Second, I am not prepared at this point to rule on the interaction of state and federal law on the issue of well determinations under the NGPA. However I definitely do not intend for this proceeding to duplicate the litigation before the Texas Railroad Commission in *Application of Phillips Petroleum Co., et al.,* Docket No. 10-77, 314 on the legality of counting extracted natural gas liquids as crude oil in calculating gas-oil ratios. I note that Movants were parties to the state proceeding and have already engaged in discovery on the same issue, and Staff's view that the allegations concerning use of refrigeration units are not material to whether the violations alleged in the show cause order exist. The Producer Group need not answer duplicative discovery requests and Movants have failed to show that their requests are not duplicative.

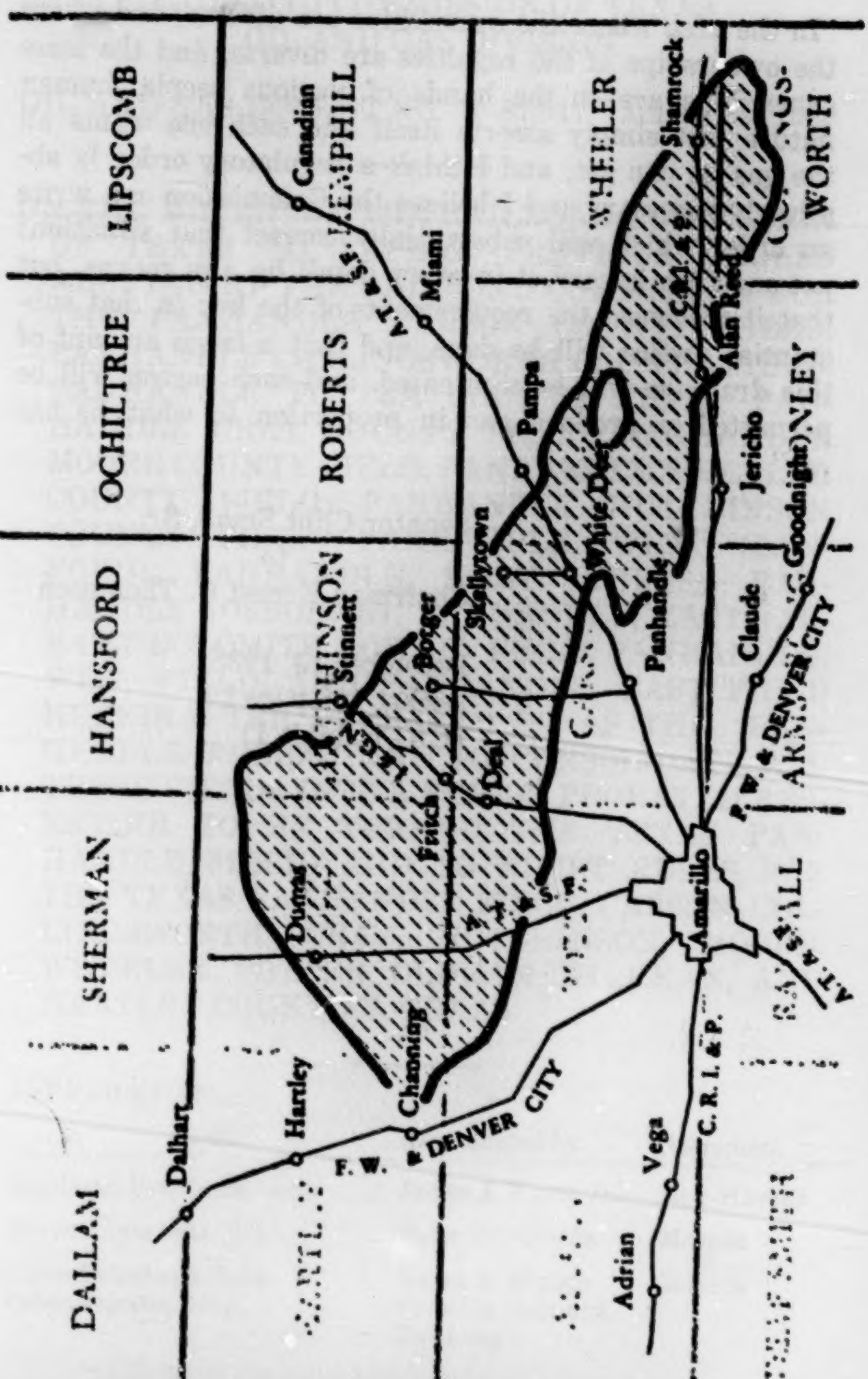
I find the Producer Group's objection to answering admission number 6 invalid. The question of whether the Producer Group claims to "own rights to produce natural gas from those wells on the subject property that are classified as gas wells" is basic and it should make its position known. The *title* to casinghead gas which is pending before state courts is a different and distinct issue. For this reason the Producer Group should answer request for admission no. 6.

APPENDIX G

RAILROAD COMMISSION OF TEXAS
OIL AND GAS DOCKET NO. 10-87,017

PROPOSAL FOR DECISION

ON THE MOTION OF THE RAILROAD COMMISSION OF TEXAS TO REPEAL PREVIOUS ORDERS ADOPTED BY THE RAILROAD COMMISSION FOR THE PANHANDLE CARSON COUNTY FIELD, PANHANDLE COLLINGSWORTH COUNTY FIELD, PANHANDLE POTTER COUNTY FIELD, PANHANDLE GRAY COUNTY FIELD, PANHANDLE MOORE COUNTY FIELD, PANHANDLE WHEELER COUNTY FIELD, PANHANDLE HUTCHINSON COUNTY FIELD, PANHANDLE, WEST (SANFORD), PANHANDLE, WEST (TUBBS), PANHANDLE (OSBORNE), PANHANDLE, EAST (ALBANY DOLOMITE, LOWER) FIELD, PANHANDLE, WEST FIELD, AND PANHANDLE, EAST FIELD HEREINAFTER REFERRED TO AS THE "PANHANDLE FIELDS" AND TO CONSOLIDATE ALL THESE FIELDS INTO A SINGLE PRORATED RESERVOIR TO BE TERMED THE TEXAS PANHANDLE FIELD; AND TO ADOPT RULES FOR THE TEXAS PANHANDLE FIELD, CARSON, COLLINGSWORTH, GRAY, HUTCHINSON, MOORE, WHEELER, POTTER, OLDHAM, SHERMAN, AND HARTLEY COUNTIES, TEXAS



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"In the area where the ownerships are diverse, and where the ownerships of the royalties are diverse, and the lease ownerships are in the hands of various people, human nature just simply asserts itself and each one wants all the gas he can get, and I think a regulatory order is absolutely necessary and I believe the Commission can write an order which will substantially correct that situation; not one that is correct in every detail by any means, but that it will meet the requirements of the law in that substantial justice will be done, and that a large amount of this drainage will be eliminated, and each person will be permitted to produce gas in proportion to what he has . . ."

—Senator Clint Small, Sr.
to
Chairman Ernest O. Thompson

December 13, 1938
Docket 108 page 29
(CIG Exhibit 1)

RAILROAD COMMISSION OF TEXAS
OIL AND GAS DIVISION

OIL AND GAS DOCKET NO. 10-87,017 March 21, 1988

ON THE MOTION OF THE RAILROAD COMMISSION OF TEXAS TO REPEAL PREVIOUS ORDERS ADOPTED BY THE RAILROAD COMMISSION FOR THE PANHANDLE CARSON COUNTY FIELD, PANHANDLE COLLINGSWORTH COUNTY FIELD, PANHANDLE POTTER COUNTY FIELD, PANHANDLE GRAY COUNTY FIELD, PANHANDLE MOORE COUNTY FIELD, PANHANDLE WHEELER COUNTY FIELD, PANHANDLE HUTCHINSON COUNTY FIELD, PANHANDLE, WEST (SANFORD), PANHANDLE, WEST (TUBBS), PANHANDLE (OSBORNE), PANHANDLE, EAST (ALBANY DOLOMITE, LOWER) FIELD, PANHANDLE, WEST FIELD, AND PANHANDLE, EAST FIELD HEREINAFTER REFERRED TO AS THE "PANHANDLE FIELDS" AND TO CONSOLIDATE ALL THESE FIELDS INTO A SINGLE PRORATED RESERVOIR TO BE TERMED THE TEXAS PANHANDLE FIELD; AND TO ADOPT RULES FOR THE TEXAS PANHANDLE FIELD, CARSON, COLLINGSWORTH, GRAY, HUTCHINSON, MOORE, WHEELER, POTTER, OLDHAM, SHERMAN, AND HARTLEY COUNTIES, TEXAS

APPEARANCES:

Party	Represented by	Alignment
Anadarko Petroleum Corp.	James J. Ward, Jr.	Non-Movant
Burnett Interests/T.C.U.	Robert C. Grable	Movant
Cabot Petroleum Corp. Cabot Pipeline Corp.	Barry K. Bishop Priscilla Hubenak Pat Long	Movant

Party	Represented by	Alignment
Celeron Oil & Gas Co.	Brian Sullivan Sandra B. Buch Cynthia M. Sullivan Paul Keeler Anna Maria Marsland	Movant
Colorado Interstate Gas Co.	Patrick Thompson Pete Schenkkan	Non-Movant
Conoco, Inc.	Tom Burton	Non-Movant
Damson Oil Company Diamond Shamrock (Maxus)	John Soule Elizabeth Miller Curtis O'Rear	Non-Movant
Dyne Oil & Gas, Inc.	Lloyd Muennink	Movant
El Paso Natural Gas Co.	John F. Nance Paul Burchell (Bob Manning) (Babe Kendrick)	Non-Movant
G.N.C. Oil Company	Lloyd Muennink	Movant
H.N.G. Oil Co. (Enron)	Joe H. Foy	Movant
J. M. Huber Corp.	C. C. Small, Jr.	Non-Movant
Mesa Operating L.P.	John Soule Elizabeth Miller	Non-Movant
Mobil Producing TX & NM	Philip F. Patman	Non-Movant
Moore County Royalty Owners Association	J. R. Lovell	Movant
Natural Gas Pipeline Co. of America	Carla Doyne Rex White, Jr.	Non-Movant
North Plains Energy Corp.	Thomas C. Moore	Movant
Northern Natural Gas (Enron)	Jane G. Alseth	Movant
Panhandle Eastern Pipeline Co.	Jack Glaves	Non-Aligned
Phillips Petroleum Company	Joe Cochran Tim George	Non-Movant
Tenneco Oil Company	Elizabeth Miller John Soule	Non-Movant
Texaco, Inc.	Joe H. Foy	Movant
Williams Natural Gas Co.	J. D. Steelman, Jr. Timothy E. McCoy	Non-Aligned

Witnesses Appearing for Movants

Name	Position
William J. Murray	Petroleum Engineer, Consultant
Clarence Stumpf, Jr.	Petroleum Engineer, Consultant
C. Ronald Platt	Petroleum Engineer, Burnett Ranch
L. C. Shelton	Interested Party
Ron Slover	Interested Party
Max Banks	Operator, Baker & Taylor
Chester Lambert	Operator, Baker & Taylor
Ed Podzemny	Operator, Baker & Taylor
Marvin Slaymaker	Pipeline Manager, Cabot
Brian Schwarz	Engineer, Cabot
Frank Groce	Operator/Geologist, GNC Company
Bill Sutton	Operator/Geologist, Dyne Oil & Gas
Billy Gillman	Petroleum Engineer, Consultant
Ronny Babcock	Grandview-Hopkins I.S.D. Board Member
Charles Buzzard	Appraiser-Gray Co. Appraisal District
S. Gray Johnston	Petroleum Engineer, Moore County Royalty Owners Association
Betty Haiduk	Interested Party
J. B. Herrmann	Operator, Herrmann Oil & Gas Company
Carroll Beaman	Operator/Engineer, American Star Energy and Minerals Corporation
T. M. Hatfield	Operator/Engineer, BHI Energy
J. Donald Clark	Petroleum Engineer, Consultant
Rex Howell	Operator/Engineer, Enron Oil & Gas Co.
J. B. Watkins	Operator/Geologist, (Various Companies)
Michael Holmes	Geologist, Consultant
Rick Johnston	Petroleum Engineer, Consultant
John Drisdale	Petroleum Engineer, Consultant
Charles Tutt, Jr.	Petroleum Engineer, Consultant
Miles Reynolds, Jr.	Chemical/Petroleum Engineer, Consultant
Robert C. MacDonald	Petroleum Engineer, Consultant
Shirley R. Clark	Manager, Burnett Interests

Witnesses Appearing for Non-Movants

Name	Position
Patrick Williams	Geologist, Tenneco Oil Company
Melissa Symmonds	Petroleum Engineer, Tenneco Oil Company
Maston Powers	Petroleum Engineer, Conoco
Thomas A. Bay	Geologist, Consultant
Ron Wilson	Log Analyst, Consultant
Wayne Ahr	Geologist, Professor, Texas A&M University
James P. Johnson	Physicist, Phillips Petroleum
Richard Strickland	Petroleum Engineer, Consultant
Clark Gillespie	Petroleum Engineer, Consultant
Henry E. Brown	Attorney, CIG

Name	Position
O. G. Poling	Lease Administration, Phillips
William Paul Loyd	Division Landman, J. M. Huber Co.
Stanley Shoemaker	Land Administration, Anadarko
Dave Oyler	Property Administration, Mobil
Garland Robinson, Jr.	Consultant, Conoco
Thomas N. Burdette	Land Manager, Damson Oil
James Weldon Prichard	Lease Records, Maxus Exploration
Mark Wesley Seale	Senior Landman, Mesa Operating L.P.

PROPOSAL FOR DECISION

HEARD ON:

February 18-19, 1986 (12 hours)
March 21, 1986 (4 hours)
January 6—May 7, 1987 (327 hours)
September 9, 1987 (7 hours)

HEARD BY:

George Singletary, Senior Technical Examiner
William Osborn, Legal Examiner
Greg Cloud, Technical Examiner

STATEMENT OF THE CASE

Purpose of the Hearing

On January 9, 1986 the Commission issued its notice of hearing in this docket. The purpose and genesis of the hearing was cited as follows:

> "A staff review of the information obtained as a result of the July 8, 1985 Commission memorandum to all operators in the Panhandle Fields indicates a substantial number of oil and gas wells are downhole commingling hydrocarbon production from the top of the Panhandle Lime to the bottom of the Granite Wash formation including the Brown Dolomite, White Dolomite, Arkosic Dolomite, Moore County Lime, and Arkosic Lime Formations.

While these formations originally may have been separate and distinct accumulations of oil and gas, the information indicates they are now in communication because of completion practices throughout these formations. So that the oil and gas hydrocarbon production from these various Panhandle formations can be effectively developed and produced to prevent waste, promote conservation, and protect correlative rights, this hearing is called and the Commission will consider consolidating all the Panhandle Fields into one, the proposed "Texas Panhandle Field", and prorating this consolidated new field as an associated reservoir.

(Hearing notice, Oil and Gas Docket No. 10-87,017, pages 1 and 2).

The notice was served on all operators in the field and generated a considerable response, resulting in designation of some 56 persons or companies as parties and an additional 50 as "interested persons".

Identification of Parties

The parties generally aligned as "movants" (supporting changes in field rules and repeal of previous orders as outlined in the hearing notice) or "non-movants" (opposing changes in the field rules). Movants include the Burnett Ranch Interests (Anne Burnett Windfohr, Texas Christian University, and Burnett Oil Co., Inc.), Cabot Petroleum Corp., Cabot Pipeline Corp., Celeron Oil and Gas Company, Dyne Oil and Gas, Inc., Enron Oil and Gas Company, G.N.C. Oil Company, H.N.G. Oil Company, Moore County Royalty Owners Association and Texaco, Inc. In addition, some operators in the field filed appearances and gave testimony in support of movants. These included Baker & Taylor Drilling Company, Herrmann Oil and Gas Company, American Star Energy and Minerals Corporation, BHI Energy, and J. B. Watkins.

Non-movants include Colorado Interstate Gas Co. (C.I.G.), Conoco, Inc., Damson Oil Co., Maxus (formerly Diamond Shamrock), El Paso Natural Gas Co., J. M. Huber Corp., Mesa Operating Limited Partnership, Mobil Producing Texas & New Mexico, Inc., Natural Gas Pipeline Co. of America, Phillips Petroleum Company, and Tenneco Oil Company. Panhandle Eastern Pipeline Co. and Williams Natural Gas Co. styled themselves as "nonaligned" but generally aligned with the non-movants.

Those of the movants who are operators principally have oil wells, and movants were often referred to in the hearing as the "oil operators" for this reason or because they sought field rules favorable to oil production. Non-movants were accordingly styled "gas operators", but the evidence showed that this was not an accurate label. The non-movants are among the largest Panhandle oil operators with Phillips, J. M. Huber, Tenneco and Mobil Producing Texas & New Mexico, Inc. among the top 10 oil producers in the field. Only one of the "oil" operators/parties made this list. (Gillespie Exhibit 63F, see appendix 3). The "gas" operators have tremendous amounts of oil acreage in the field also. The examiners propose that if generalization is necessary, it is more accurate to style movants as the "new operators" and non-movants as the "old operators". Each side has one or two parties which do not match these designations but have aligned with them anyway.

Size of Field

The gas discovery well in the Panhandle Field was drilled by Canadian River Gas Company in 1917, and the oil discovery well was drilled by Gulf Production Company in 1921. The field is 1.76 million acres in size, with 10,796 oil wells and 3,510 gas wells producing in June of 1986. (Tr. 8676, Johnston Exhibits 5 and 11). The average oil well now makes approximately 2 barrels of oil and 16 mcf of casinghead gas per day, and average

gas well makes about 114 mcf/day. (Tr. 5195, 8967, 8430 line 1, see 5235 line 20 estimating average of 114 mcfd, Johnston Exhibit 11). Cumulative production to mid-1986 is estimated at 1.24 billion barrels of oil, 32 trillion cubic feet of gas well gas and 6.4 trillion cubic feet of casinghead gas. (Gillespie Exhibits 5 and 10, Tr. 6424-6425, Johnston exhibit 3) Remaining reserves are estimated by non-movants at approximately 100 million barrels of oil and 2.8 trillion cubic feet of gas well gas. (Gillespie Exhibits 5 and 10). Movants estimated that remaining oil reserves were substantially higher and provided several estimates based on various types of calculations. The most conservative estimate (of oil recoverable from the traditional gas area) was 400 million barrels of oil. (Tr. 6330). The reservoir on discovery had a uniform pressure of about 435 pounds, which is subnormal for depth. This field is now in an advanced stage of depletion, with current pressures ranging from 0 to about 50 pounds. The producing mechanism is primarily dissolved gas drive, in contrast with the other large field in the state, East Texas, which is primarily water drive.

Area of Development

The vast majority of oil wells are located along the northeast rim of the field, referred to at times as the "traditional" oil area. The remainder of the field has historically been considered to be productive primarily of dry gas (the "traditional dry gas area"), but some recent developments, especially in Moore County, are proving that there is oil in this part of the field also. The Moore County oil play is not prolific; the average well there makes only 4 barrels per day, but this is double the field-wide average. (Johnston Exhibit 16). The producing GOR of these wells, which averaged 22,432:1 in 1986, is fairly high.

Recent oil completions in other counties have proved less successful; Hutchinson County, for example, had over

1100 new oil completions in the last ten years but the 1986 average oil rate was one barrel per day. (Johnston Exhibits 20, 23).

Although the statistics are clouded by the presence of LTX liquids which were reported as oil in the late 1970s and early 1980s, it is clear that recent oil development in the traditional gas area of the field has to some degree tended to arrest the natural fieldwide oil decline rate. (Johnston Exhibits 10A, 13). In particular, drilling and new oil completions between 1978 and 1985 seem to have arrested a 20 year decline in the oil rate, with calculated incremental oil recovery to date of about 23 million barrels and future increment projected at 41 million barrels by Rick Johnston, Petroleum Engineer for movants. (Johnston Exhibit 2, Tr. 5129 line 23, 5176). Some increment is apparent regardless of controversy over the use of exponential vs. hyperbolic decline curves. (Tr. 5309-5310). Calculation methodology can vary the numbers substantially, and some of Mr. Johnston's numbers are optimistic, but his conclusion that known oil reserves have increased due to new drilling is correct. (Tr. 5352-5353, 5370).

The new operators seek field rules which would encourage further exploration in Moore County and elsewhere. The old operators are satisfied with the current rules, and it cannot be said that they have no interest in exploration for oil—Phillips Petroleum, for example, claims over 170,000 acres of oil rights in Moore County alone. (Poling Exhibit 1)

REGULATORY HISTORY

Problems in the 1930s

Following completion of the discovery well in 1918 it was rapidly apparent that a tremendous field extended across the Panhandle. By the early 1930s, operators in the field faced a problem identical to that of their coun-

terparts in the East Texas Field: lack of a market for their product. As a result, a number of wasteful practices arose in the Panhandle, foremost of which was the operation of gasoline stripping plants. These plants took advantage of a physical property of natural gas to condense on compression and form a clear liquid condensate which was useable in its raw state as automobile fuel. This condensate was referred to as "natural gasoline" and following its removal some 90% of the original gas volume remained as a dry residue gas of no value, and was flared. Enormous quantities of natural gas were required to manufacture natural gasoline in this manner due to the inefficient conversion ratio. Because of the poor conversion ratio gasoline plants paid a very low price for their feedstock. Roy White, an engineer with the Texas Company, testified in a 1932 Commission hearing that the gasoline plants were then paying only 1/10 of a cent per mcf vs. 3½ cents per mcf being paid for the quantities of gas which could be transported by then existing pipelines. (Hearing of September 1, 1932, p. 47, CIG Exhibit 1)

The only other market for natural gas was for use in manufacturing carbon black, but demand was limited. In 1933 there were 25 carbon black plants in operation and they produced 71% of the total output in the entire United States, the vast majority of which was used to manufacture rubber. (Gillespie Ex. 50). Like gasoline stripping plants, the first carbon black plants used wastefully inefficient conversion methods and consumed tremendous quantities of gas in the manufacturing process.

Unencumbered by comprehensive field rules, operators were producing as much as they were technically able. In a November 1935 hearing, H. M. Stallcup, vice-president of Skelly Oil Company, described these practices:

> With the advent of intensive development in the Borger area, and the fact that a great majority of

the oil wells produced large volumes of gas accompanying the oil, there were started several large natural gasoline plants, or they are often referred to as casinghead gasoline plants. Some of these large volumes of gas accompanying the oil at that time, and for subsequent years, was literally and accurately described as casinghead gas, that is gas accompanying the oil from the oil reservoir, inevitably and unavoidably produced with the oil. Additionally, as gasoline plants were constructed, and particularly in the latter part of 1926, and in the early part of 1927, when the first carbon black plants were built in the field, thus making the first and only considerable market for such residue gas from these plants, the operators of oil wells started what is to me the vicious practices of either improperly completing the oil wells in the first instance, or by ripping and shooting or in any other matter that might occur to them, manhandling such properly completed wells so as that they not only produced their oil but almost unbelievable quantities of gas from the upper gas horizons. This afforded tremendous casinghead residue gas, and this, to me illegitimate, gas from the upper horizons was made available for any markets that might be obtained, and the only one to date, with very few exceptions, that has developed has been for the manufacturing of carbon black. Those gasoline plants continued to increase in number throughout the area as the area was developed, to the extent that at the present time there are 41 gasoline plants of one type and another constructed and operating throughout the field. Similarly there have continued to be constructed and operated carbon black plants to the extent of approximately 25 at the present time.

(Hearing of November 19, 1935, p. 130-131, CIG Exhibit 1)

By June of 1934, the Commission's Pampa office reported that residue gas was being vented or flared into the atmosphere at the rate of some 1 *billion* cubic feet per day. At that time it was the largest gas field in the world. (Gillespie Exhibit 50, page 9). Emby Kaye, a Skelly Oil Company vice-president, condemned these practices in a 1934 "Petroleum Engineer" article:

> "But if this (pre-1933) East Texas Gasoline is an unwanted child, born of wedlock, the new natural gasoline brought into production in 1933 and to this writing, in the Texas Panhandle is a child *born of rape.* If the former had to be produced as a conservation matter, the latter is the result of the very negation of conservation. The wanton waste of billions of cubic feet of natural gas for the extraction of the pittance yielded from the gasoline can never be excused, except as selfishness and greed."
>
> (Gillespie exhibit 50, p. 17, emphasis supplied)

A committee of engineers representing the major gas operators in the field published a report on gas wastage in 1934, wherein they asserted:

> "It is common knowledge that it has long been the practice of many operators to rip casing which formerly shut off the big gas pay, in order to permit the production of excessive volumes of gas with the oil."
>
> (Gillespie Exhibit 50 page 14)

This was acknowledged earlier by Roy White, the Texas Company (Texaco) engineer, who testified to the Commission in 1932 that as much as 70% of the "casinghead gas" was "coming from the upper formation, in what we call the dry gas reservoir" and stated his belief that such high quantities of gas were produced "through improper completion, either intentional or otherwise, or perhaps through intentional ripping of the casing." (Oil and Gas

Docket No. 64, pp. 41, 57, September 1, 1932, CIG Exhibit 1).

Legislative Reactions in the 1930s

In response to problems in the Panhandle and wasteful practices elsewhere in the state the Texas Legislature passed a comprehensive conservation statute known as House Bill 266 on May 1, 1935. The act provided in relevant part:

> Section 1. Declaration of Policy:
>
> > In recognition of past, present, and imminent evils occurring in the production and use of natural gas, as a result of waste in the production and use thereof in the absence of correlative opportunities of owners of gas in a common reservoir to produce and use the same, this law is enacted for the protection of public and private interests against such evils by prohibiting waste and compelling ratable production.
>
> * * *
>
> Section 3. The production, transportation, or use of natural gas in such manner, in such amount, or under such conditions as to constitute waste is hereby declared to be unlawful and is prohibited. The term "waste" among other things shall specifically include:
>
> (a) The operation of any oil well, or wells with an inefficient gas-oil ratio.
> [now Tex. Nat. Res. Code § 86.012(a) (1)]
>
> * * *
>
> (1) The production of natural gas from a well producing oil from a stratum other than that in which the oil is found, unless such gas is produced in a separate string of casing from that in which the oil is produced.
> [now Tex. Nat. Res. Code § 86.012(a) (11)]
>
> * * *

Section 4.

(b) No person in possession of or operating any oil well shall produce from such well natural gas found in a horizon productive of natural gas only.

[now Tex. Nat. Res. Code. § 86.097]

* * *

Section 22.

The Commission shall be vested with a broad discretion in administering this law, and to that end shall be authorized to adopt any and all rules, regulations or orders which it finds are necessary to effectuate the provisions and purposes of said law.

(Act of May 1, 1935, Ch. 120, 1935 Tex. Gen. and Spec. Laws 318)

Celeron et. al. correctly note that the bill "does not contain any reference to perforations of gas-oil contact", commenting that "the gas operators merely infer the presence of such language." In the opinion of counsel for Celeron, "the purpose of the bill was not to impose restrictions on perforations in oil wells relative to a gas-oil contact, but . . . to prevent waste." (Celeron Reply to Closing Statements, p. 30). The examiners respectfully disagree with the Celeron position, and submit that the purpose of the bill was to prevent waste of every type then common in the field, including among others the commonly known problem of high performations discussed by Mr. White, Mr. Stallcup, and the 1934 Engineering Committee. Section 4(b) of the bill, now § 86.097 of the Natural Resources Code, was part of a special amendment sponsored by Amarillo Senator Clint Small, Sr. (1935 Senate Journal, p. 1229). The Senator recognized the existence of a "horizon productive of natural gas only".

Commission Action On House Bill 266

Following the pasage of H.B. 266, the Commission commenced investigations and convened hearings to consider rules for the Panhandle Fields. Since one provision of the act defined waste as operation of a well at an inefficient gas-oil ratio, Commission engineers conducted a survey of ratios in the field and reported in July of 1935 that oil wells in the field with gas-oil ratios between 0 and 5000:1 produced 92.6% of the oil, a figure which rose to 98.2% if the cut-off was raised to 25,000:1. (Hearing of July 18, 1935, p. 72, CIG Exhibit 1). At that hearing, Commission Chief Engineer Griffin testified that the proper way to complete an oil well in the field so as to minimize producing GOR was to set the oil string "into the producing formation. In other words, *below the contact of the oil and gas.*" (Hearing of July 18, 1935, p. 85, CIG Exhibit 1, emphasis supplied).

After receipt of further evidence and testimony that summer and fall, the Commission issued a comprehensive, 12 page order on December 10, 1935 establishing rules for the Panhandle Fields. The contemporary understanding of the meaning and purpose of H.B. 266 is evident from the requirements set forth in the order, which is excerpted in pertinent part as follows:

> WHEREAS, In conformity to House Bill No. 266 . . . the Commission has held public hearings . . . and from intensive and comprehensive study of this field . . . the Commission finds:
>
> * * *
>
> The Oil and Gas so far encountered in the Panhandle field has been found, with minor exceptions, in four separate strata, namely: the dolmite (sic), the arkosic-dolmite (sic), the gray limestone, and the granite wash. These four formations overlie one another and though they are normally separated one from another by impervious strata, they are interconnected as is shown by the fact that the virgin

pressure of oil and gas from all of them was 430 pounds per square inch at sea level, regardless of the location in the field.

* * *

The oil wells in the oil pools in the field were, as a general rule, drilled through one or more gas-containing strata before entering the oil-containing stratum, and, in many instances, the wells were so completed as to cause production of gas from the gas strata along with the oil and gas from the oil stratum, with the result that tremendous quantities of gas have been produced with the oil, large portions of its coming from gas-producing strata above the oil-producing strata. This gas was in large part blown into the air, and it has been estimated that in excess of two trillion cubic feet of gas produced in this manner has been wasted into the air.

* * *

From testimony adduced at hearings and from a study by its Engineering staff, the Commission finds that . . . after the distillation of the organic materials into oil and gas, the water, oil and gas segregated in porous strata started arranging themselves in accordance with their densities; that due to the buoyant force caused by the different specific gravities of water, oil and gas, the lighter oil and gas migrated upward in the water contained porous strata, interbedded between impervious strata.

* * *

IT IS ORDERED, That no gas well or oil well shall be permitted to produce gas from different levels, sands or strata at the same time through the same string of casing, and that if the Commission believes this to be happening in any case, the Deputy Supervisor is hereby authorized to make gas-oil ratio, bottom-hole pressure, charcoal test of the gas for its gasoline content, specific gravity determination of

the gas, analysis of the gas, a study of the well log, and any other tests at any time for the purpose of comparing the gas with gas from offset property, or tests pertinent to the information desired, and the owner of such well is hereby directed to do all things that may be required of him by the Commission's Agent to properly make such test.

* * *

IT IS FURTHER ORDERED, That this docket be kept open for the introduction of further evidence or information so that the Commission may, at any time modify or amend this order or enter such other or further general or special order or orders as may be necessary to correct or relieve any inequalities, injustices or inequities that may result from the enforcement of the provisions of this order.

(December 10, 1935 Order, CIG Exhibit 6)

Commission Posture 1935-1985

Commission employees have had occasion to make a number of public statements about the Panhandle Fields over the years. A few of these are excerpted:

1936 A.M. Crowell, Natural Gas Engineer:

"The question of gas/oil ratio in the Panhandle Field is a tremendous one. Many wells drilled in the oil areas of the Panhandle Field have been improperly completed and in some cases it has been found that the inside string of casing has been perforated, causing large amounts of gas to be produced with the oil. These high gas/oil ratio wells produce a small per cent of the total oil produced in the Panhandle Field but by their operations and production of large amounts of gas are depleting the field of its reservoir energy, causing low pressure areas and bringing about a condition where a large amount of oil will never be recov-

ered which could be recovered if all the wells were operated on an efficient gas/oil ratio."

(CIG Exhibit 4, page 5)

1937 V. E. Cottingham, Director of Production:

"Another thing that causes high gas-oil ratios in the Panhandle Field is the way the wells have been completed; they drill down through a gas horizon on into another horizon, an oil horizon, and possibly that is one of the chief reasons for high gas-oil ratios in the Panhandle Field, and that condition was brought about, of course, in the early days, the early history of the field, because gas had no market value and they sought to get as much gas coming with that oil and just let your gas and oil blow.

I am saying that a large part of the gas produced in the Panhandle—the difference between the casinghead gas and dry gas in the Panhandle is largely one of definition. In other words, a great deal of it comes from a strata above the oil produced in those oil wells that were drilled prior to any proration or any regulation with reference to containing the gas, oil and water to the original strata."

(CIG Exhibit 1, April 13, 1937, pp. 64-65, 116)

1948 Ernest O. Thompson, Chairman (and former mayor of Amarillo):

"If there is any field that we know the data on in the state of Texas, it is this field. We have had hearings and hearings and hearings. I think we have more complete data on the Panhandle Field than any field in the country, unless it is East Texas."

(CIG Exhibit 1, May 13, 1948, p. 184)

1956 J. G. McClintock, Deputy Supervisor:

"MEMORANDUM TO ALL OPERATORS OF OIL WELLS IN ALL FIELDS IN THE PANHANDLE OF TEXAS, DISTRICT #10"

"It has been brought to the Commission's attention that a few operators in this district have perforated the casing in the dry gas zone and are reportedly selling such as casinghead gas. Please be advised that in the future any violation of this nature will be dealt with accordingly, as it is definitely in violation of the rules and regulations of the Railroad Commission of Texas, Oil and Gas Division."

(Murray Cross-Examination Exhibit 1)

1977 J. C. Herring, Senior Staff Engineer:

"In reviewing both the rules for the Panhandle Fields as well as the Statewide rules, it appears that it is the intent of the Commission that oil wells in the various Panhandle Fields should be produced from below the gas-oil contact and with the lowest gas-oil ratio possible. In reviewing the production reports filed in the various Panhandle Fields and the numerous tests conducted by Commission personnel, it appears that there are a number of oil wells in the Panhandle Fields with perforations above the gas-oil contact which are currently producing gas through the tubing-casing annulus directly to a sales outlet. It appears that these oil wells are not only in violation of the Commission's intent as previously stated, but also in violation of the Commission Rules."

(Memorandum to Phillip Russell, Director of Field Operations. Released to Panhandle Fields operator Wallace Bruce in 1982. Murray Cross-Examination Exhibit 2)

1985 Jim Morrow, Director, Oil and Gas Division:

"TO ALL OPERATORS IN THE PANHANDLE FIELDS"

"It has come to the attention of the Commission that many wells have been completed in the Panhandle Fields in a manner which does not comply with current field rules.

* * *

Completing an oil well or working over an oil well so that any portion of the producing interval is above the gas-oil contact may not be consistent with the (cited) orders, rules and statutes. Likewise, completing a gas well or working over a gas well so that any portion of the producing interval is below the gas-oil contact may not be consistent with the (cited) orders, rules and statutes." (Citing Rule 3 of Oil and Gas Circular 16-B, amended, Special Order Nos. 10-316 and 10-3087, Statewide Rules 10 and 13 and Texas Natural Resources Code §§ 86.012 and § 86.097.)

(Official notice, Hearing Notice X, page 8)

LTX Proceedings

In the fall of 1983, the Commission held a 30 day hearing in Docket No. 10-77,314 to consider whether liquids produced from low temperature extraction (LTX) units in the Panhandle fields could be counted as oil for well classification purposes. Some 1000 of these machines were placed in service between 1977 and 1983. (Tr. 5191). On May 13, 1985 the Commissioners signed an order finding that the product of LTX units was not crude oil in the statutory sense, and that to classify wells based on a calculation counting these products as crude oil would be contrary to the statutory definition of an oil well.

The Commission order of May 13th required that all LTX wells be retested within 75 days. Many units were

apparently taken out of service immediately as only 515 wells were submitted for testing—251 passed, 71 failed and the remainder were inconclusive or "unacceptable tests" for various reasons. (Tr. 5178, 5180). The use of these machines was not prohibited, but it is forbidden to count their product as crude oil for well classification purposes.

FERC Actions

In February of 1984 the Federal Energy Regulatory Commission (FERC) commenced its own investigation of the high perforation problem, ordering 37 oil well operators (Respondents) in the Panhandle Fields to show cause why they had not violated various sections of the Natural Gas Act (NGA) and Natural Gas Policy Act of 1978 (NGPA). Of primary concern were alleged violations of NGPA § 504, which effects a ceiling price (§ 104 price) for gas dedicated to interstate commerce before enactment of the statute (before November 8, 1978). In 1984, Dorchester Natural Gas Company operated some 35 gas wells in the area of investigation. These were open hole Brown Dolomite wells completed between 1933 and 1949 on some 21,000 acres in Carson and Gray Counties (subject acreage). Between 1978 and 1984, Respondents completed some 196 "oil" wells on the subject acreage and qualified all of their "casinghead gas" for NGPA § 103 or § 109 prices for "new" gas (substantially higher prices permitted for new than for old gas, this in order to encourage exploration for new gas reserves as a policy objective of the NGPA). FERC convened a hearing to determine whether Respondent's "casinghead gas" was in fact being produced from a dry gas zone already producing through Dorchester wells, thus dedicated § 103 gas.

Twenty-eight of the Respondents were operating LTX units on their leases, and based on facts arising during the hearing the FERC judge determined that "In most cases Respondents' W-2 forms filed with the Railroad

Commission do not show the perforations in the Brown Dolomite made after initial completion in the Granite Wash." (Docket GP84-23-000, 30 FERC 63,017 at 65,030). Based on ASTM-86 distillation tests, recombination analysis and phase diagram comparison, specific gravity analysis, gas-oil ratio analysis, and geological evidence, the administrative judge concluded that:

> "most of the gas produced by most of the Respondents is not casinghead gas because it is not gas indigenous to an oil stratum and produced from that stratum with oil, and that most of the respondents are producing gas which would otherwise be produced by Dorchester." *Id.* at 65,048.

The judge interpreted Railroad Commission field rules in making this determination, which she based on a gas-oil contact theory.

> "Since the Railroad Commission has established a division of the reservoir so that the Panhandle West Gas Field is that portion of the reservoir lying above the gas-oil contact, it follows that Dorchester's proration unit is that portion of the reservoir above the gas-oil contact which lies beneath each 640 acre unit assigned to a Dorchester well. Perforations in the Brown Dolomite by themselves are not conclusive evidence that respondents are producing and selling [§ 104 dedicated, or "old" gas]. . . What is determinative is whether or not respondents' gas production comes from above the gas-oil contact because this would mean that such production was not casinghead gas. . . . *The location of the gas-oil contact is determined in each individual wellbore and may vary from one well to another.* (emphasis supplied) *Id.* at 65,048.

Counsel for movant operators in this Railroad Commission proceeding have asserted that Judge Murray did not correctly interpret the Panhandle Field rules.

As in the instant proceeding, respondent operators in the FERC hearing submitted evidence of high oil in the Brown Dolomite, on which the Judge commented:

> "It is obvious from the record that it is not unusual, for example, to find shows of oil in cores and various kinds of rock samples but these isolated bits of visual evidence are unreliable indicators of whether crude oil will be produced at all, or in any meaningful quantities. (*Id.* at 65,048).

The Judge commented that FERC enforcement staff viewed this case

> "as revealing only the tip of the iceberg of a widespread practice where parties, under the guise of drilling new oil wells, transform old (relatively cheap) dedicated natural gas into new (high cost) undedicated gas. (*Id.* at 65,035).

All respondents were eventually ordered to cease violations of various provisions of the NGPA. In this hearing we looked at the rest of the "iceberg".

CHANGED CONDITIONS

The Biblical "threescore and ten years" have passed since discovery of the Panhandle field, and the passage of time has seen two generations of operators come and go. Comprehensive field rules were passed in 1935 to curb the abuses of the first generation, but by 1956 a second generation had to be reminded of the perforation commandment. Celeron has glossed over the 1956 edict of Mr. McClintock to all operators in the field that high perforations were "definitely in violation" of Railroad Commission rules. They have only one comment about the memorandum in all of their filings, that "There is no evidence in the record of any inspections or imposition of penalties resulting from Mr. McClintock's statement." (Celeron Reply, p. 35). The examiners respectfully submit that this is not accurate. In fact, due to

fieldwide investigation at the time, some 70 wells were reclassified from oil to statutory gas wells (Oil and Gas Docket 108, #10-37,495, Hearing of May 7, 1958, p. 19 lines 1-4, p. 20 line 14, CIG Exhibit 3).

We now face the influx of a relatively new group of operators, Like their predecessors in some ways, but different in others, they are pushing the field rules to the limit and have requested that the Commission "clarify" them. These limits have been clouded in recent years, perhaps not so much by operator agression but by advances in wellbore completion technology which permit the production of some oil from zones formerly thought productive of dry gas only.

There have been substantial advances in wellbore completion technology since 1935 which may qualify as "changed conditions" under the doctrine set forth in *Railroad Commission v. Aluminum Company of America*, 380 S.W.2d 599 (Tex. 1964). (See appendix 6). According to J. B. Watkins, operator, and as discussed in early Commission Docket 108 hearings in the 1920s and 1930s, the first completion method of choice was explosion of nitroglycerine to fracture the formation. (Tr. 3917-3919). Operators began to experiment with acid treatment in the mid-1930s. (CIG Exhibit 1, May 11, 1936, p. 259; Gillespie Exhibit 27). Although earlier references appear, Henry Rogatz did not attribute significance to hydraulic fracturing (gelled water, sandpropping, etc.) until 1954 (Bay Cross-Examination Exhibit 20). This type of formation stimulation is widely used today.

Early operators encountered substantial problems with wax and paraffin, as discussed in 1928 by E. J. McKee, Phillips Petroleum Co. Chief Production Engineer:

> "All the waxes encountered are to a great extent chemically inert and to date we have been unable to find any chemical that will react with them. The only thing that has any apparent effect is heat."
>
> (Bay Cross-Examination Exhibit 6, Original page 283)

Such chemicals now exist and are used routinely in the field. For example, a 1976 workover on the NGPL No. 4-T Texas Company fee well included treatment for paraffin with a mixture of kerosene and "compound C" (Bay Cross-examination Exhibit 20). Baker & Taylor makes a practice of flushing its new wells with a 2% KCL solution to minimize paraffin problems. (Podzemny Exhibit 1).

Modern day operators have access to electric wireline log technology unavailable in the 1920s and 1930s. A wide variety of tools are now available to precisely measure formation density, porosity, and permeability, water and hydrocarbon saturations, etc., the analysis of which has been elevated to a separate science undreamed of in the pre-nuclear age when gamma rays and neutrons were but ideas in the minds of a very few scientists. Similar advances in chromatograph and fluorescence analysis would have staggered those who completed the Canadian River Gas Company discovery well in 1917.

Former Commissioner Bill Murray testified that the impact of these technological changes was dramatic. He discussed the evolution of logging and stimulation technologies and improvements in cementing technology and concluded that the majority of wells completed today would not have been completed or produced 50 years ago. (Tr. 83). Medford McCoy, a Conoco Engineer, studied the field in 1953 and reported that in the gas area, "Wells which have been drilled deep enough to reach the gas-oil contact were drilled for oil, but the density of the formations at this level was prohibitive to production in most cases." (Powers Exhibit 3 page 7) The examiners agree with Mr. Murray's conclusion, but note that some part of the phenomena must be attributed to economics. One acknowledged expert on the field, Henry Rogatz, spoke thus on the early days:

> "Wells with initial productions below 250 barrels were disappointing and almost uncommercial unless

their daily capacity could be increased. In the Depression and ten cent-a-barrel days, wells of this size often were plugged." (Bay Cross-examination Exhibit 25, page 29)

The examiners submit that dramatic advances in wellbore completion technology since 1935 satisfy the "changed conditions" doctrine set out in *Aluminum Company of America*, supra, and that these changes will support a revision of the field rules.

RESERVOIR THEORIES

Movants and non-movants in this proceeding differed in their theories of reservoir mechanics and producibility of remaining reserves. Experts for movants submitted that substantial quanities of producible oil remain to be recovered from levels high in the formation, areas historically thought productive for the most part of dry gas only. Experts for non-movants disputed this assertion and took the position that while there might be residual oil high in the gas cap portion of the field, it is generally immobile to flow and not producible to the surface on primary recovery.

Movants' Theory

The principle witnesses on fieldwide reservoir theory for the movants were Dr. Michael Holmes, geologist, and Dr. Robert MacDonald, Petroleum Engineer.

Geology

Holmes Exhibit 3 depicts the structural geology of the field, overlying and generally aligned with the Amarillo uplift, which is bounded on the north by the Anadarko basin and the south by the Palo Duro basin. The field is generally productive of hydrocarbons over a 1000 foot interval which various but ranges most often between —100 feet and +900 feet subsea depth, being composed of several discrete and usually identifiable formations, including the basal fractured granite, Granite Wash,

Arkosic Dolomite, Moore County Lime, White/Brown Dolomite, and Panhandle Lime (top seal). Dr. Holmes was of the opinion that the reservoir was originally full to the top with oil at 1500 pounds, and that the gas we see in the field today was liberated from this oil due to a pressure decline of over 1000 pounds before discovery. (Tr. 4064). The Granite Wash, a clastic deposit, displays radical variations in thickness and is not present at all in some areas of the field. The White and Brown Dolomites, subsequent carbonate depositions, are according to Dr. Holmes heterogeneous and not subject to easy categorization as far as permeabilities and porosities. He testified that it was "a completely different geologic framework than the Red Cave," a higher formation which was the subject of recent Commission action in docket 10-86,552. (Tr. 4994 lines 24-25). Dr. Holmes and his support staff put together a computer database of all W-2 completion information available from the Commission, Dwight's Energy Data, Geomap Company and Petroleum Information Company. This database was the source of many of their maps and cross-sections.

Dr. Holmes postulated a fracture-matrix theory of the Brown Dolomite which was the subject of much controversy. Simply put, he believes that gravity segregation of oil and gas in the reservoir was inefficient, such that substantial amounts of "high oil" remain to be recovered, either from catchment basins or fractures intersecting capillary trapped oil.

Catchment Basins

Dr. Holmes believes that within the Brown Dolomite there are perched basinal traps full to the spill point with oil. (Tr. 4698 line 2). The permeability barriers which prevent downward migration of oil were thought to be either anhydrite or carbonate mud flat seals. (Tr. 4626). Holmes Exhibit 51 (corrected 53A) shows the location of a few high oil plays which Dr. Holmes attributed to this phenomena.

Capillary Trapping

Dr. Holmes was of the opinion that capillary forces had trapped a tremendous amount of oil high in the Brown Dolomite, primarily within the dolomite matrix. He believes that the dolomite is ubiquitously fractured, and if these fractures are intercepted by a wellbore or wellbore stimulation and sufficient flowthrough of gas is permitted, the matrix oil can be produced. Dr. Holmes' conclusion was based substantially on his examination of cores from the Celeron 16-12P well in Potter County and the Baker & Taylor 8-209 well in Moore County. Photographs of various core sections were presented for the proposition that there was free oil high in the Brown Dolomite, with fracturing intermittent and "quite fine", but open in many places (Tr. 4121, 4126-4127, Holmes Exhibit 23A, Tr. 4149).

Engineering

Using a volumetric equation, Dr. MacDonald relied on Dr. Holmes' work and calculated oil-in-place in the "traditional dry gas area" at 85.5 billion barrels of which he thought a "very small fraction" could be recovered. (MacDonald Exhibit 39, Tr. 6359) By way of an alternative approach to calculation of this fraction, he offered a material balance equation showing that 2.5 billion barrels of oil 'might be expected to be found" in the traditional gas area. (Tr. 6232). Examiner Osborn pressed Dr. MacDonald on his calculation:

Q: "Have you done any calculations or do you have any opinion as to how much of that oil is recoverable?"

A: "I believe it's possible to recover in the neighborhood of 400 to 500 million barrels."

Q: "What is the basis for your calculation that 400 to 500 million barrels are recoverable?"

A: "It's really a judgment . . . it's an outside limit." (Tr. 6653-6654)

By way of comparison, Dr. MacDonald calculated that original oil in place in the traditional oil area was 36.4 billion barrels, and production from that area over the last 70 years represents the majority of total cumulative production fieldwide, 1.24 billion barrels by his calculation. (Tr. 6651-6652)

Non-Movants Theory

The principal witnesses on fieldwide reservoir theory for non-movants were Mr. Thomas Bay, Geologist, Dr. Wayne Ahr, Geologist, and Mr. Clark Gillespie, Petroleum Engineer.

Geology

Mr. Bay was in substantial agreement with Dr. Holmes' theory of the depositional processes which took place to form the reservoir. He disagreed with Dr. Holmes' analysis of the Brown Dolomite, finding that it was a rather uniform and predictable formation generally present as a blanket deposit, which was "completely separated. . . by shales" and "not in communication" with the underlying Arkosic Dolomite. (Tr. 7829-7830). Mr. Bay's study of the field was based primarily on cable tool drilling logs from some 10,000 wellbores. These logs report the observers' perceptions of formation lithology and hydrocarbon shows, which Mr. Bay deemed accurate for the purposes of estimating distributions of oil and gas. This assumption, central to his methodology, was subjected to severe criticism by movants. Based on his study of these records, Mr. Bay constructed a number of cross-sections illustrating his picks of gas-oil contacts, or first producible oil. He defined "gas-oil contact" as a gravity segregation phenomenon resulting in a transition zone below which is oil and above which is gas. (Tr. 7108-7109). Mr. Bay did not attempt to pick a gas-oil contact within any formations underlying the Brown Dolomite "because of the distribution of porosity within each of these units being rather erratic and discontinuous, and, in

my opinion, being local reservoirs." (Tr. 7386). Within the Brown Dolomite, he did not find a single, uniform fieldwide gas-oil contact, but rather a number of contacts in different regions, ranging from a low of +150 to a high of +342. (Bay Ex. 52, 64). These variations were attributed to structural features which trapped oil at high levels in some places. Other than these places, which include the Mother Goose, Masterson, White Deer and Deep Lake Grabens, Carson County basin margin and Rockwall County School Land areas, he did not ascribe to the theory of high pools of oil in the Brown Dolomite advanced by Dr. Holmes.

Professor Wayne Ahr testified on reservoir fracturing for non-movants. Dr. Ahr studied cores from the J. M. Huber Co. No. 3 Crudgington and No. A-3 Otis Phillips wells and prepared exhibits detailing his findings. He asserted, in disagreement with Dr. Holmes, that fractures do not play an important role in fluid transmission through this reservoir. (Tr. 8191) He characterized the Brown Dolomite as an excellent reservoir with "ample porosity and permeability in the intercrystalline pore network . . . irrepective of fractures". (Tr. 8207)

Engineering

Clark Gillespie, petroleum engineer, performed a fieldwide study of the reservoir for non-movants and projectd remaining oil recovery at some 100 million barrels. (Tr. 8477 line 8). By his calculation, except in the Moore and Potter County areas, the drilling of new oil wells "has not *significantly* altered the projected ultimate recovery of oil from the field". (Tr. 8541 lines 8-17, emphasis supplied). He speculated that there might be some unusual reservoir characteristics along the northern flank of the Moore County platform area which contributed to higher oil averages in that region, but felt a need for further study before making a firm conclusion. (Tr. 8972 lines 7-16). In Mr. Gillespie's opinion, efficient gravitational

segregation over most of the field caused the accumulation of gas in the structurally high parts of the field and the accumulation of oil in the structurally low parts, with exceptions in a few anomalous areas such as the Deep Lake, White Deer, Mother Goose and Lefors Grabens. (Tr. 8473). This opinion was based on his examination of some 10,000 old cable tool drillers' logs. Gillespie exhibit 32, a histogram of first reported shows in these wells, shows that of 6324 reporting oil encounters, 95% occurred below +250 feet. (Tr. 8578). He prepared a number of cross-section exhibits (52-55b) showing his picks for gas-oil contact or transition zones, and concluded that as a general rule, "when producible oil and gas zone gas occur in the same wellbore, a gas-oil contact is present and can be identified." (Gillespie Ex. 2). Mr. Gillespie did not assert that there was a single unified contact across the entire field. (Tr. 8923-8924). He found some variation in the contact level, and on occasion could not pick a contact at all. (Tr. 8755 line 14).

When questioned on his definition of gas-oil contact, Mr. Gillespie offered the following:

> "The gas-oil contact is a point which may be defined with respect to initial fluid distribution or capillary pressure, with considerations as to the point of zero capillary pressure or the point below which the porous permeable rock is entirely filled with liquid. That is, perhaps, a rigorous reservoir engineering definition.
>
> I think it can also be defined, and I have defined it, I believe, in other matters, as the point above which commercial oil production cannot be obtained. And that would probably be a point at the upper portion of the so-called transition zone above the 100% liquid level.
>
> * * *
>
> The one that I have used with respect to my testimony in this proceeding today would be the latter.

> I do not certainly disagree with the first one that I stated; that is, the point of 100% liquid saturation but I believe that in a practical oil field operation that certainly with regard to drilling completion, the latter would be the one that would be more commonly utilized."
>
> (Tr. 8875-8876).

On cross-examination Mr. Gillespie's attention was directed to a number of instances of shows of oil above what he would pick as a gas-oil contact. (Cross-examination ex. 26-32). He was of the opinion that these shows did not indicate producible oil. (Tr. 9028).

Mr. Gillespie discussed a recent trend of increases in casinghead gas withdrawals which he considered excessive. (Ex. 63D-F). The examiners consider these exhibits very important and have reproduced them in appendix 3.

Examiners' Opinion on Reservoir Theory

The examiners are of the opinion that there was efficient gravity segregation of hydrocarbons in the majority of the Panhandle field, such that it is frequently possible to pick a gas-oil contact by one of several means. We believe that there is residual oil high in the dry gas cap, but that saturations are generally so low as to be immobile to flow and production in practical quantities. "Practical" as used here means that quantity which would attract a prudent operator to drill an oil well.

Gas-Oil Contact

The presence of a gas-oil contact or transition in this field has been noted or inferred for decades.

> "The upper limit of this oil zone is about 200 feet above sea level whether the oil is found in granitic sands or dolomite."

(CIG Ex. 5; Baur, *Oil and Gas Gields of the Texas Panhandle*, 10 Bull of Am. Assoc. of Pet. Geologists 733, 744 (August, 1926))

"Oil is usually found where the positions of the porous formations lays from 110 feet above sea level to nearly sea level. There are, however, exceptional occurences."
(CIG Ex. 1, RRC Director of Production V. E. Cottingham, Docket 108, p. 355 [November 19, 1935])

"Gas is found in all of the producing formations where present on the higher parts of the regional structure, oil being present on the north flank and maintaining a general level between sea level and 200 feet above."

(Herrmann Cross-Examination Ex. 3; *History of Development of General Geology of the Panhandle Fields of Texas,* 12 Panhandle—Plains Historical Review, p. 7 [1939])

"According to Mr. Rogatz,[1] the oil is found between gas-oil and oil-water contacts and all of the oil, water and gas is considered as being one huge system."
(CIG Ex. 2; RRC Engineer James Hall, Docket 10-17,040, pp. 4-5 [January 12, 1950])

"Anywhere across this field . . . the position of the gas-oil contact holds esentially the same position with respect to sea level . . . regardless of whether the oil is in the Granite Wash or whether it is in the White Dolomite or the Brown Dolomite."

(G. L. Knight, Phillips Petroleum Company District Geologist, *Id.* at 16.)

The examiners have no doubt that operators who do not look for a gas-oil contact will not find one. Some movants

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[1] Movants recognized Henry Rogatz as "a noted authority on the field" and "the grand old man of geology of the Panhandle Field." (Tr. 3007, 9552)

testified that they were unable to locate a contact or transition zone, but cross-examination evidence indicated that they were often able to pick contacts when convenient or requested in prior years:

Max Banks: "There is no gas-oil contact". (Tr. 1026).

But Baker & Taylor's own well files identify high perforations as located in a "gas zone" and lower oil perfs as located in an "oil zone" (Lambert cross-examination exhibits 3,5,6, and 8).

Bill Sutton: "I don't think you could pick a gas-oil contract". (Tr. 2396).

But on a Commission H-1 form Mr. Sutton himself previously listed a gas-oil contact for this well. (Sutton cross-examination exhibit 2).

Billy Gillman: "Every core that I've ever seen laid out from the top of the Brown all the way down always shows a certain amount of oil in it." (Tr. 2590).

But Mr. Gillman's company has filed at least one H-1 form (on their Haynes Lease—03776) showing a gas-oil contact.

J. B. Herrmann: "I can't find any (gas-oil contact) in my wells". (Tr. 3080).

But in 1966 one of Mr. Herrmann's employees in filling out an application to inject fluid (H-1 equivalent) listed a gas-oil contact of +150 feet on their Hardin Lease (00821) well no. 4. (Herrmann cross-examination exhibit 2).

T. M. Hatfield: "We can't identify a gas-oil contact in this field." (Tr. 3395).

But none of Mr. Hatfield's wells (which are located primarily on the Burnett Ranch) are open to the upper formations. (Tr. 3416)

The full text of Max Banks' remarks provides some revealing insight into the motivation for this recent inability to locate a gas-oil contact.

"We never knew the gas-oil contact was even a factor in an oil well up here. We find out now, after FERC gave you a crutch to limp with, that it is a factor, so now we have to prove that there is no gas-oil contact." (Tr. 1026).

The examiners suggest that when both commercially producible oil and dry gas are present in a wellbore, it is almost always possible to locate a gas-oil contact or transition zone by one of the following methods:

1. Selective Interval Test

Many of movants' witnesses were in agreement that an operator *who desires to do so* can determine oil and gas intervals in an individual wellbore by isolating various depths with retrievable bridge plug and packer or other methods and testing the isolated interval for production.

Chester Lambert: "It's possible, yes." (Tr. 1120 line 25)

Frank Groce: "True." (Tr. 2322 line 21)

S. Gray Johnston: "That's correct." (Tr. 2939 line 23)

Carroll Beaman: "Quite elementary". (Tr. 3173 line 8)

Rex Howell: "Yes . . . most of them (intervals in his wells) were selective isolated by a packer and a bridge plug." (Tr. 3660-3661)

Michael Holmes: "In terms of identifying fluids within the reservoir . . . you can complete the well and test it individually." (Tr. 4115-4116)

S. Gray Johnston, Petroleum Engineer witness for the Moore County Royalty Owners Association, testified that most of the operators he worked with selectively tested their zones as a matter of course. (Tr. 2939).

2. Wireline Logs

Most of the witnesses in this proceeding were not professionally qualified to interpret wireline logs. Those who were agreed that this type of data could assist in picking a gas-oil contact.

> Frank Groce: Log water saturation calculations are "90 percent accurate . . . in depicting whether you have oil or gas production from where you're perforated." (Tr. 2218) *and* Neutron/density crossover "indicates that there is gas there." (Tr. 2324)
>
> [Two curves are compared for crossover. The density log curve is produced by a shallow-reading tool and the compensated neutron log curve is generated by a tool which "sees" back about a foot into the formation.]
>
> Bill Sutton: "Yes." (Q—"on the porosity log if you had a neutron density cross-over, that that could be productive of a gas only zone?") (Tr. 2460)
>
> Michael Holmes: "I conclude that in general the fluids in the matrix can be determined from logs." (Tr. 4021) "The logs emphatically tell you where the oil and gas and the water are located." (Tr. 5046)
>
> Clark Gillespie: "Under the proper circumstances with the proper suite of logs being available . . . one may be able to observe the ending of gas effects and thereby gain a pretty fair indication of whether or not a gas-oil contact has been penetrated." (Tr. 9104)
>
> "This is a tool that may be used, although I would also have to say that although logs are a tool that may be used, regrettably many operators . . . most operators do not run a suite of logs that even comes close to permitting the identification of a gas-oil contact from well logs if one has been penetrated." (Tr. 9106)

3. Cable Tool Log Records

These records of fluids and formations encountered in over 10,000 early wells exist in several geological libraries and depositories around the state. During the Depression one of President Roosevelt's W.P.A. projects included sorting and cataloging these records, which are on file among other places at the University of Texas Bureau of Economic Geology. The fluid levels reported by observers on these wellbores are generally consistent; 95% (of 6324 reporting oil encounters) showing first oil at or below +250 feet. (Gillespie exhibit 32). The accuracy and reliability of these records was attacked by some witnesses for movants; for example, petroleum engineer Miles Reynolds commented: "My opinion is that the cable tool drilling record information is not a reliable tool in trying to determine where all potential zones of productivity are." (Tr. 5853). This was a rather carefully qualified condemnation. Those witnesses who were familiar with the cable tool drilling and logging process generally agreed that the records were a valuable tool for determining fluid locations in the reservoir:

> Bill Murray: (Cable tool driller's logs are) "as reliable as anything that existed then, and I'm not sure there is anything that is better now" (for locating first appearance of oil).
> (Tr. 197)
>
> Clark Gillespie: "I certainly do agree with it (the statement that driller's logs are comparable to a continuous open hole drillstem test) . . . Cable tool drilling method has as one of its obvious principles that one uses a rock bit to pound up the rock into small chips that can be removed from the wellbore with a bailer . . . the driller, his tool dresser, or geologist, if he was onsite, could observe almost on a foot by foot basis the nature of the rocks and what, if anything, was coming into the wellbore . . . I would say that in many cases the—a cable tool

driller's log would be a better and more reliable indication of what the formation contained at the time of drilling and would be perhaps less subject to interpretation of modern well logs would be."
(Tr. 8549-8550)

Michael Holmes: "If we are drilling wells, as was done in the early days, with cable tools, we have essentially a continuous drillstem test on the well, from which if we're careful in our records, and if the data allow us to do this, we can record flows of gas, shows of oil, mists of oil and so on."
(Tr. 4115)

Chester Lambert: "I don't question what's on the logs."
(Tr. 1129)

Tom Bay: "When we pulverize this rock with the cable tool driller, with the bit hitting on that rock, that, in my opinion, breaks it up more than any fracturing that one might do in the subsurface in order to stimulate the flow. So, if there is any oil in that matrix, we certainly should see it when we do pound that rock and pick it up in that bailer."
(Tr. 7920-7921)

The examiners are of the opinion that cable tool drilling records are a generally reliable indicator of fluid levels and helpful in picking a gas-oil contact or transition zone.

4. Coring and Sample Cuttings

A number of witnesses for movants conceded that examination of returns from wellbores was useful in picking fluid levels. Comments in this regard:

J. B. Watkins: "The process that I normally use in drilling and completing wells from a geological and completion standpoint is to examine the cuttings, and where you have live shows of oil, use

that as a basis for the top part of your producing formation if you're drilling an oil well."
(Tr. 3823)

Bill Sutton: "I would core a well and use the core information for completion."
(Tr. 2445)

Q: "You've indicated that the core analysis indicates what intervals are likely to be productive of gas and what intervals are likely to be productive of oil."

A: "Yes."
(Tr. 2457)

Michael Holmes: "Another source of information is mud logging, of monitoring of the mud stream or the fluid stream from which you are drilling the well, as to what hydrocarbons or what materials are being brought to the surface."
(Tr. 4115)

"Another source of data is core information. Cut a core and you can measure fluids in that core and make interpretations, make estimates, at least as to what—at least you know what fluids are there, and then perhaps estimate what might be there before the flushing process of the coring."
(Tr. 4116)

"I'm sure you're aware that oil fluoresces; in other words, if you bombard it with ultraviolet light, it reflects back in the visible spectrum . . . and it represents the presence of oil."
(Tr. 4130) [See also Tr. 4135]

Chester Lambert: Q: "Do you recall the question that was asked you about distinguishing between oil show versus gas show by Mr. Cochran?

A: Yes, I do.

Q: Let me ask you very simply: does gas reflect a fluorescence or is it just oil that reflects a fluorescence?

A: Oil is what reflects a fluorescence."
(Tr. 1182)

The examiners are of the opinion that analysis of formation samples is a useful tool for locating a gas-oil contact.

5. What the Neighbor Found

The examiners are in agreement with the assertion of Clark Gillespie that one task prudent before drilling new wells is the prior analysis of "production performance of the nearby leases." (Tr. 9091). Some witnesses for movants conceded the value of this analysis in predicting the location of oil zones:

> Frank Croce: Q: "And that type of study of surrounding producing wells has been to assist you in knowing where to perforate for oil and where to perforate for gas; is that right?
>
> A: That is a tool used in that procedure, Yes." (Tr. 2322)
>
> Billy Gillman: "You rely on the knowledge of similar wells in close proximity of the well you're working on."
> (Tr. 2622)

Perforation and completion information is readily available for all wells in the field, either by analysis of Railroad Commission files (W-2 data) or purchasing the relevant statistics from one of the commercial reporting services.

The examiners concur with the opinions of many experts over the decades that where commercially producible oil and dry gas are both present, the two generally meet at a gas-oil contact or transition zone which can be located *if desired.* We agree with Bill Murray, who testified, "I have clearly stated from a conservation engineer if it is possible, when it is possible to determine a gas-oil contact, it is desirable for conservation reasons to perforate below the gas-oil contact." (Tr. 131). Mr. Murray was of the opinion that such determination is not possible in the Panhandle fields, and we respectfully dis-

agree with his conclusion. Operators have managed to pick a gas-oil contact on the H-1 forms for many years, generally without problems, and did not report difficulties to the Commission until after the FERC hearing. Two generations of operators have come and gone without leaving a substantial trace of this difficulty in transcripts of prior proceedings concerning the field, and we can only conclude that they had no such problem. These difficulties in picking a gas-oil contact are a notably new development.

No party asserts that there is a *single, uniform* gas-oil contact across the field. The cross-sections prepared by Mr. Bay show that there are regional contacts which vary with structure as should be expected in a field of 1.7 million acres. Some of these contacts may be in reality transition zones of up to 50 feet in thickness, but the evidence shows they can generally be located where present.

Fractures

The examiners made a personal inspection of core samples from the study wells and conclude that the Brown Dolomite is not "widely fractured" with fractures still open as asserted by Dr. Holmes. (Tr. 9581). We agree with Dr. Ahr that "the bulk of those things are filled with anhydrite—and they are very small." (Tr. 8115). Scanning Electron Microscope and thin section photographs submitted by Dr. Ahr show that there is no need to postulate a complicated fracture matrix system to explain Brown Dolomite oil production. We note that each side provided thorough analysis on only two cores and feel that this is not much evidence on which to judge a field of 1.7 million acres, but based on what we have seen we do not find pervasive open fracturing in the Brown Dolomite. In a 1961 paper for the Panhandle Geological society, Henry Rogatz noted fracturing in all formations but concluded that due to extensive an-

hydrite impregnation within the Brown Dolomite "there is trapped a goodly part of the oil in the individual pores . . . [so that even with a waterflood] . . . large quantities of oil will be irretrievably trapped within the formation." (Bay Cross-examination Ex. 25, page 35). We are in agreement with Mr. Rogatz.

Catchment Basins

Dr. Holmes postulated traps of perched oil being held in the Brown Dolomite by anhydrite seals or carbonate mud flat deposits. The examiners have problems with Dr. Holmes' logic, which was somewhat convoluted in explanation of the genesis of these deposits. He conceded that the formations were originally full to the cap with water, which was pushed down by encroaching oil of a lighter density, and then had to explain why his traps were not full of water rather than oil. He accomplished this by assuming that the permeability barriers were in fact semi-permeable and acted as a barrier to downward flow of oil but *not* water. (Tr. 4663, 4677, 4697-4698, 4711) This seemed too convenient to the examiners and they requested data on the relative molecular sizes of water and oil molecules. The following was provided:

Water	.3 nm
Methane	.38 nm
Benzene	.47 nm
N-Alkanes	.48 nm
Cyclohexanes	.54 nm

(Tr. 4713)

Dr. Holmes' theory requires that his semi-permeable membranes permit the passage of a molecule .3 nm in size, but not .4 nm. No evidence was submitted to support such a precise limit, and the examiners are of the opinion that this remains an unproven theory. We do disagree with Dr. Ahr's assertion that the Brown Dolomite is porous and permeable from top to bottom. Analysis of

Bay Exhibits 72-78 show the following instances of intervals at least 8 feet thick with 0% to 1% porosity. (Disregarding shale breaks and the top 50 feet of the formation.)

— Huber No. 3 Crudgington From 2365 to 1372 feet

— NGPL No. 1-1 Bennett from 2628 to 2638 feet

— HNG No. 1 Sneed "A-2" from 2410 to 2420 feet

— Cities Service No. 4 Burnett B-3 from 2653 to 2661 feet

— Top O'Texas Prod. No. 2 Hayden from 2684 to 2692 feet.

It must be conceded that there are a few uncontrovertible instances of producible oil high in the Brown Dolomite above an expected gas-oil contact.

1. The J. M. Huber No. 66 State of Texas -A- well, located about 1 mile south of Mr. Bay's line M-M', tested 1.5 BOPD and gas TSTM from perforations at +367 to +461. Mr. Bay's pick for top of transition zone in this area is +244. (Tr. 7766-7767).

2. The Phillips Petroleum Co. No. 10 Osborne well, located about 3 miles south of Mr. Bay's line A-A', tested 24 BOPD and 5600 mcfg/d (statutory gas well) from perforations at +452 to +562. Mr. Bay picks this Brown Dolomite area as gas only. (Tr. 7772, Bay Cross-examination Exhibit 3). The Osborne No. 2 well nearby is perforated from +282 to +402 and after 1975 workover and reclass to oil tested 4.1 BOPD and 264 mcfg/d. (Bay Cross-examination Exhibit 3).

3. The Sesco Operating No. 5 Laycock is perforated from about +300 to +500 in the Brown Dolomite in Wheeler County. IP was 2 BOPD and 17 mcfg/d. (Holmes Exhibit 55 A-1).

4. The Rockwall Petroleum No. 1078 Roberts is perforated from about +425 to about +525 in the Brown Dolomite in Gray County. IP was 11 BOPD and 53 mcfg/d. (Holmes Exhibit 55 A-1).

These and a few other occurrences of "ghost oil"; high, commercially producible oil with no known explanation, are rare. The majority of other instances submitted by movants of high oil in the Brown Dolomite have structural explanations as analyzed in Bay Exhibit 80 and summarized in Appendix 1.

RESERVES

High Matrix Oil

The examiners have not seen substantial evidence to support the position taken by movants that high residual oil is producible. The most dramatic evidence against producibility was the frustration encountered by Dr. Holmes in his effort to get oil to flow from a high level in the Celeron No. 16-12P Bivins well. He was present when the well was cored, and saw live oil high in Brown Dolomite.

> "I left the cores on the pipe rack, and if you [came] back every five minutes or so, you would see more oil coming out of the fracture system, and even a week or so later, . . . we cracked them open and there it was. You could smell it. There's live oil, very high in the structure."
> J. E. Watkins: "The process that I normally
> (Tr. 4125-4126)

In answer to a question by examiner Osborn about producibility of this oil, he responded:

> "I think you would have to test the well for probably a matter of days, maybe even a matter of weeks, before you would see the response of the oil." (Tr. 4162)

Based on what he saw, Dr. Holmes recommended various perforations to Celeron in an attempt to produce this high

oil. Celeron made the perforations but was unable to produce *any* of this high oil in *34 days* of testing. Holmes' conclusion:

> "The poor reservoir doesn't have any energy down there."
> (Tr. 4150)

Dr. MacDonald, chief engineering witness for the new operators, agreed with Geologist Holmes' interpretation of the fracture-matrix theory of the reservoir and performed studies to make a calculation of the amount of oil in place in the traditional dry gas area of the reservoir. Based on these studies he concluded it is "possible to recover in the neighborhood of four to five hundred million barrels" from this area. (Tr. 6653-6654). Two studies formed the basis for this conclusion; a compositional material balance analysis and a volumetric analysis. The former generated a figure of 2.5 billion barrels of oil in "intimate contact" with the dry gas, being the amount calculated as necessary to cause the rise in specific gas gravity seen in the field. (Tr. 6232). The latter generated a figure of 85.5 billion barrels of oil in place of whicch he conceded a "very small fraction" would be recovered (MacDonald Exhibit 39, Tr. 6359).

The volumetric calculations performed by Dr. MacDonald are subject to substantial variation in results with minor changes in input. His formula will not work for R sub S values higher than about 177 (solution gas measured as a ratio of standard cubic feet per stock tank barrel on discovery). (MacDonald Cross-Examination Exhibit 22, Tr. 6405, 6409). He testified that he had heard that R sub S in the field ranged from 140 to 230, but that he had not "really looked at that top range" (Tr. 6412, 6415 lines 9-19). By way of example of the input sensitivity problem, if Dr. Holmes' calculation of hydrocarbon volume of 35 million acre feet was high, and actual volume was 30 million acre feet, the resulting value drops from 85.5 billion barrels to 9.4 billion

barrels. (Tr. 6418). Similarly, if the calculation of gas in place in the gas area was revised downward from 40.3 trillion cubic feet to 37 trillion cubic feet, the resulting value for oil in place increases to 121 billion barrels. (Tr. 6438). All of these figures far exceed MacDonald's calculation of cumulative oil production of 1.24 billion barrels over the last 70 years. (Tr. 6651-6652).

Volumetric and Compositional Material Balance equations are subject to another limitation which was acknowledged by Dr. MacDonald; neither indicates whether oil is spread uniformly through the rock at low saturations or concentrated in fractures or other accumulations. These equations do not provide information about the location of oil within a formation. (Tr. 6422, 6493).

The fundamental premise behind Dr. MacDonald's work is his reliance on Dr. Holmes' fracture-matrix theory of the reservoir. Dr. MacDonald's production forecast model assumes casinghead gas production will "put a drawdown on the matrix (and) more oil into fracture(s) for subsequent production". (Tr. 6339-6340). But he conceded that fractures had been reported without regard to whether they might be filled with anhydrite or some other barrier to flow. (Tr. 6533 line 9). A lack of discrimination in this regard detrimentally affects the reliability of the conclusion as to producibility of the "intimate oil" calculated by the witness.

The examiners are of the opinion that residual oil saturations in the gas cap are in most instances locked up too tight to flow to a primary recovery well. Dr. Richard Strickland and Dr. James Johnson performed tests to simulate reservoir conditions and submitted conclusive evidence that residual saturations were generally immobile to flow. Dr. Strickland agreed that Dr. Holmes' capillary pressure was a valid explanation for high residual oil saturations, but asserted that for the most part this oil could not be produced to the surface. (Tr. 8422).

A number of other experts referred to this or other high immobile oil as "dead oil". (See Frank Groce at Tr. 2367, Tom Bay at Tr. 7789 and Miles Reynolds at Tr. 9368).

The examiners are of the opinion that they have not been presented with a reliable estimate of the amount of *recoverable* oil existing in the traditional gas area of the field. The evidence supports a conclusion that some amount does exist, and the presence of some undiscovered amount is therefore not unreasonable, but the examiners have not seen convincing proof that the 400 to 500 million barrels of recoverable oil postulated by Dr. MacDonald can be produced. He asserts this oil can be produced "provided you place a pressure differential across this system" but later concedes that "the fracture system . . . does not really contact but a very small proportion of this total oil in place." (Tr. 6286, 6359). Dr. Ahr's evidence that many of these fractures are filled with anhydrite presages some difficulty in producing the oil which is present in the dry gas area of the reservoir.

Low Perf Gas Wells

If some new operators in the field are guilty of overaggressive completion practices, the same is true of some old operators. Just as an oil well operator is required to stay out of a dry gas zone, a gas well operator should stay out of any oil zone below the gas he is producing, refraining from ripping his casing top to bottom in a horizon where any free gas removal will diminish drive energy required for oil recovery. Movants did not give much attention to this problem, but examiner questioning during the hearing and analysis of the exhibits indicates that some operators when completing gas wells may not take particular care to stay out of deeper oil bearing horizons or horizons productive of oil nearby. The following are presented as examples of this problem:

1. C.I.G. No. A-3 Crawford gas well

A 1973 well perforated from +326 to+1197 across the fractured granite basement, Granite Wash, Moore County Lime and Brown Dolomite. This well with IP of 7758 mcf/d, is located some 9000 feet south of the Hufo No. 3 Johnston oil well, which was completed in 1980 for IP of 8 BOFD and 180 mcf/d at a GOR of 22,500:1; perforations +352 to +542 in the fractured granite *only.* (Bay Exhibit 59, assuming Hufo correctly reported perforations).

Examiner Cloud: "What about the gas in the basement there? Don't you think it is helping to drive the oil to the Hufo No. 3 Johnston oil well? Don't you think that gas needs to be conserved against the oil production in the Hufo No. 3 oil well which is down dip?

Tom Bay: Mr. Examiner, you are asking me questions beyond the scope of my study on this." (Tr. 7506)

2. C.I.G. Nos. A-4 and A-17 Kilgore

A-4 is a 1955 well with IP of 885 mcfd, perforations from +124 to +684. A-17 is a 1969 well with IP of 5600 mcfd, perforations from +169 to +818. Both wells are completed deep into the Arkosic Dolomite. (Bay Exhibit 64)

Adjacent is an oil well, the Hufo Production No. B-5 Johnson, perforated from +780 to +233, 1983 IP of 7.1 BOPD at a GOR of 63,904:1 (this well is probably perforated too high, see Tr. 7538). Two and 1/2 miles west is the Texas Gas Producing Company Brown Lease, with several abandoned oil wells. The closest of these, the No. 1 Brown, tested 71 BOPD at a GOR of 2436:1 on a 1961 test from perforations at +304 to +312. This lease(s) was abandoned in 1968 with cumulative production of

61,400 barrels of oil. (Letter of November 9, 1987, counselor Elizabeth Miller to Examiner Osborn). One must question whether excessive production of deep gas by C.I.G. caused the premature abandonment of these oil wells by depleting their drive energy.

Examiner Osborn: "Let's look at the CIG A-17 Kilgore. Do you feel that the perforations in that gas well below the Arkosic Dolomite—Moore County Lime contact should be squeezed off?

Tom Bay: "That I don't know sir, because we have not made a gas-oil contact study in the Arkosic Limestone and Granite Wash." (Tr. 7538).

3. C.I.G. No. A-2 Read gas well

A 1937 well perforated from +600 to +1202 across the Granite Wash, Arkosic Dolomite, Moore County Lime and Brown Dolomite. 1937 IP was 56,700 mcfd, and following 1955 workover and deepening increased to 68,000 mcfd. (Bay Exhibit 66)

4. Kerr-McGee No. 1 Wilbar gas well

A 1935 well perforated from −6 to +703, this well is located in Gillespie study area 10 where he picks a gas-oil contact at +160. Clark Gillespie: "I would think . . . the lower part of the well should be plugged off." (Tr. 8744)

5. Diamond Shamrock No. 2 Schlee gas well

A 1985 well perforated at various intervals from +173 to +729 in the Arkosic Dolomite, Moore County Lime and Brown Dolomite. 1985 IP was 3420 mcf/d. (Bay Exhibit 58). Clark Gillespie testified that pressure depletion of the Arkosic by the Schlee well "could, to some extent" affect the gas-drive movement of oil to nearby oil wells. (Tr. 9223)

6. Conoco No. 2 E. L. Smith gas well

Total depth of 3230 feet, with top of oil zone indicated by company records at 3172. Maston Powers,

Conoco Engineer, conceded "they really should have plugged it off." (Tr. 6977 line 14).

Examiner Osborn: Mr. Gillespie, you're showing six or seven wells, I believe, gas wells completed down into the Granite Wash?

Clark Gillespie: Yes.

Examiner Osborn: Does the gas produced from those wells dissipate drive energy used to produce Granite Wash oil?

Clark Gillespie: I think, as the studies of Dr. Strickland indicated, whether a gas well or an oil well is perforated above the gas-oil contact, the withdrawal of gas either by an oil well or a gas well perforated above the gas-oil contact immediately above an oil zone may have some detrimental effect on oil recovery. (Tr. 8624).

Lest there be any doubt that some gas wells are perforated down into oil bearing zones, attention is directed to Stumpf exhibits 14-18 concerning gas wells reclassified to oil with no downhole workover. These wells, the El Paso Natural Gas Wattenbarger -A- Nos. 3 and 4 and Bell No. 5-D, and the Texaco B. H. Love No. NCT-1-3 well, all made very little oil on new IP after conversion, with an average of only 1.3 BOPD. The question remains, what production would they have made if produced for oil 25 years ago when they were new wells and the reservoir pressure was substantially higher? We have no way of knowing.

Further attention is directed to Reynolds exhibits 6, 7, 20 and 21 illustrating other conversions from gas to oil. The Terra Energies J. R. Nicholson No. 1, drilled in 1961, was equipped to pump oil in 1973 and produced at a test rate of 9 BOPD with a GOR of 27,777:1. (Reynolds exhibit 6). This well is perforated from about +375 to +425 (from log; note discrepancy with schematic) and

is located in one of the Appendix 1(4) areas, Carson County Basin Margin (East), where a contact at +450 is assumed correct. The Crown Bobbitt no. 5 well, drilled in 1948 three sections to the east, was converted to oil in 1970 after fracture stimulation resulted in production of 31 BOPD at a GOR of 10,000:1. (Reynolds exhibit 7, see also Stumpf exhibit 18). This well is perforated from about +325 to +380, a level presumed acceptable since it is within the same special area as the Terra no. 1 Nicholson.

The Phillips Petroleum Osborne No. 2 was completed for gas in 1949, and recompleted for oil in 1967 from perforations at +282 to +402. (Reynolds exhibit 20, Bay cross-examination exhibit 3). A nine year history submitted as Reynolds exhibit 21 shows that this is a high GOR well, ranging up to 72,593:1 on 1978 test, but most recently it was making a 4 BOPD at a GOR of 14,250:1. The well is located in an appendix 1 (4) special area, the Deep Lake Graben, where a contact is presumed at +350.

Reynolds exhibit 20 illustrates four other gas completions (open hole) which went deep enough to hit oil, and 15 to 20 years later were reclassified from gas to oil:

Roy Production No. 4 Bills
Phillips Petroleum No. 1 Bralley -A-
Diamond Shamrock No. 10 Ryan
Diamond Shamrock No. 1 Myers

THE COMMISSION'S MANDATE

Statutory Requirements

The Railroad Commission has among its many jurisdictions the duty to regulate and prorate production of oil and gas in order to prevent waste, promote conservation and protect correlative rights (Tex. Nat. Res. Code §§ 85.201, 85.202(b), and 86.081(a)).

Chapters 85 and 86 of the Texas Natural Resources Code contain numerous statutory definitions of waste, of which the following are relevant in this docket:

1. § 85.046(a)(1) (1) operation of any oil well or wells with an inefficient gas-oil ratio . . . (Commission may prescribe permitted ratio).

   (3) underground waste or loss, however caused . . .

   (6) operating a well or wells in a manner that reduces or tends to reduce the total ultimate recovery of oil or gas in any pool

   (7) loss incident to or resulting from the unnecessary, inefficient, excessive, or improper use of the reservoir energy, including the gas energy or water drive, in any well or pool. . .

2. § 86.012(a)(11) the production of natural gas from a well producing oil from a stratum other than that in which the oil is found unless the gas is produced in a separate string of casing from that in which the oil is produced.

The duty to protect correlative rights is addressed in the following relevant provisions:

1. § 85.202(a)(4)
2. § 86.042(5)

(The Commission shall) require wells to be drilled and operated in a manner that will prevent injury to adjoining property.

CASE LAW INTERPRETATIONS

The meaning of these statutory definitions and requirements and the Commission's obligations arising from them have been addressed by the Texas courts. Following are discussions and definitions from some of these cases:

1. *Gulf Land Co. v. Atalntic Refining Co.*, 131 S.W.2d 73, 80, 85 (Tex. 1939)

   Appeal of a Rule 37 Order

   > "The term 'waste', as used in oil and gas Rule 37, undoubtedly means the ultimate loss of oil. If a substantial amount of oil will be saved by the drilling of a well that otherwise would ultimately be lost, the permit to drill such well may be justified under one of the exceptions provided in Rule 37 to prevent waste.
   >
   > The Commission is not compelled to absolutely confine itself to the lone question as to whether such well will save oil that otherwise would be lost, but may also take into consideration waste above the ground, and the orderly and scientific development of the field."

2. *Hawkins et. al. v. Texas Co.*, 209 S.W.2d 338, 342, 344 (Tex. 1948) A benchmark Rule 37 case rejecting the theory of "more wells, more oil", this case expands on the use of the qualifier "substantial" in the *Gulf Land* case.

   > "There is no proof in the record that a *substan-tial* amount of oil would be saved by drilling the additional well. The only evidence suggesting the drilling of that well would prevent waste is the testimony of the witness Hudnall . . . he testified that the recovery of oil from the Hawkins tract would be increased by the drilling of an additional well. Thereupon, to the question whether the increased recovery would be a substantial or

only a trivial amount, he answered that it would be substantial in percentage, but due to the fact that the sand was thin the total amount would not not be very great. There is no evidence in the instant case that a *substantial* amount of oil would be saved by the drilling of a tenth well. The testimony is merely that the recovery of oil from the tract would be increased, or that a small quantity not otherwise produced or a greater percentage of oil would be recovered." (emphasis original)

3. *Phillips Petroleum Company et. al. v. American Trading and Production Corporation et. al.*, 361 S.W.2d 942, 945-946 (Tex. Civ. App.—El Paso 1962, writ ref'd n.r.e.)

A suit concerning ownership of proceeds from sale of illegally produced oil. The Court of Appeals addressed the role of correlative rights in Commission decisions.

"The function of the Railroad Commission with respect to the exercise of its regulatory powers in the oil and gas industry is not confined solely to the prevention of waste and the conservation of a natural resource. The Commission also has the duty, in cases where it has been determined (as it has here) that a common reservoir exists in which numerous parties share certain rights and interests, to promulgate field rules and orders applicable to such common reservoir for the protection of the correlative rights of all who are entitled to take from the common reservoir or share in the proceeds from such production.

Conservation statutes and orders of the Railroad Commission . . . are designed to afford each owner a reasonable opportunity to produce his proportionate part of the oil and gas from the entire pool and to prevent operating practices injurious to the common reservoir.

> The consensus of authority appears to hold that the right of an owner to recover oil and gas from beneath his own land is qualified and is limited to "legitimate operations". Each owner whose land overlies a common reservoir has a like interest, and each must exercise his right with some regard to the rights of others, and must submit to such limitations as are necessary to enable each to get his own."

4. *Railroad Commission v. Manziel*, 361 S.W.2d 560, 572 (Tex. 1962).

Dispute concerning a waterflood injection program.

> "The Commission has two primary duties in the administration and control of our oil and gas industry. It must look to each field as a whole to determine what is necessary to prevent waste while at the same time countering this consideration with a view toward allowing each operator to recover his fair share of the oil in place beneath his land. In carrying out these duties, there has devolved upon the Commission the power to promulgate rules, orders and regulations that control the industry, and such are issued pursuant to the police power of the state, and that power may invade the right of the owner of the land to the oil in place under his land as long is it is based on some justifying occasion, and it is not exercised in an unreasonable or arbitrary manner.
>
> It follows from the nature of oil and gas that the use by one of his power to seek to convert a part of the common reservoir to actual possession may result in an undue portion being attributed to one of the possessors of the right to the detriment of the other. Hence, it is within the Commission's power to protect the vested rights of

> all the collective owners, by securing a just distribution, and to reach the like end by preventing waste."

Celeron et. al. discuss this case in their closing statement at page 38, and take the position that it has no relevance since it is addressed to "drainage *across lease lines*" (*id.* at 572, their emphasis supplied). They reference the Natural Resource Code § 85.202(a)(4) duty to prevent "injury to *adjoining property*" (their emphasis supplied) and assert this protection does not extend to severed gas rights, which are instead "akin to the rights of an undivided interest owner in a tract". (Celeron Closing, p. 38). The Legal Examiner respectfully submits that the more appropriate analogy would be to horizontal severance of mineral rights into two separate estates, each meriting protection of correlative rights. "Horizontal divisions of the oil, gas and other minerals under a tract of land creates estates of equal dignity. There is no lesser and greater estate involved." *Gibson Drilling Co. v. B & N Petroleum, Inc.*, 703 S.W.2d 822, 826 (Tex. App.—Tyler, 1986, no writ). While not exactly the situation at hand, this seems the better analogy given the concept of an upper dry gas zone above the oil and water zones which was generally accepted in the 1920s and early 1930s when the interests were severed.

Celeron et. al. take the position that if there were correlative rights deserving protection, they no longer exist because "all of the gas which was in the gas phase when the field was discovered has [already] been produced by the gas wells." (Celeron Reply p. 38, citing "Dr. MacDonald's unrebutted testimony" at Tr. 6360). *However*, Dr. MacDonald later conceded that *the same was true* for casinghead gas production from oil wells, calculating for this a cumulative total of some 6.4 trillion cubic feet, being about twice the amount of solution gas which he calculated was originally present in the traditional oil rim. (Tr. 6423 line 10, 6424-6425).

Given that correlative rights in the field are deserving of protection, how shall this privilege be reconciled here where it conflicts with the Commission's mandate to prevent waste? The Commission has faced this dilemma in the past, and it is clear from the case law that prevention of waste is the dominant mandate.

> "Between protecting correlative rights and protecting the public interest of preserving our state's natural resources, the prevention of waste has been held to be the dominant purpose. The Commission, by controlling the oil stored in a common reservoir, is enabled to carry out the dominant purpose of preventing waste.

Texaco, Inc. v. Railroad Commission, 583 S.W.2d 307, 310 (Tex. 1979).

To say that a concern is dominant does not mean that it is exclusive. In the case of *Railroad Commission of Texas v. Fain*, 161 S.W.2d 498, (Tex. Civ. App.—Austin 1942, writ ref'd w.o.m.), Awoeb Oil Company challenged a Commission fieldwide proration order for the Minnie Bock oil field in Nueces County, asserting that the order caused waste in their company's three wells. The court considered a conflict in Commission mandates and stated:

> "Even if it be admitted that all of (Awoeb's) contentions as to waste applicable to their particular wells be true, the Commission was confronted with the problem as to how conservation as to the entire field would best be subserved; and must decide that question with reference to the field as a whole. . . When they (statutory definitions of waste) conflict, or present a dilemma, as they appear to have done here, it is for the Commission to determine what on the whole will best conserve the natural resources. And if that determination finds support in substantial evidence, though the evidence be conflicting, the order should stand." (*Id.* at 500).

To Awoeb's assertion of confiscation, the court replied:

> Nor is the fact that the Commission's order will result in economic loss to appellees controlling. Any order of the Commission limiting density of drilling, daily allowable per well, or controlling storage, transportation and marketing necessarily affects property values and profits from production of oil. But this is necessarily incident to the police power of the state to regulate any business affected with a public interest, so long as it treats all alike. (*Id.* at 500).

Celeron et. al. assert that "(b)ased on the facts of this case (Docket No. 10-87,017), the Railroad Commission must confine its attention to the issue of waste only". (Brief of Celeron et. al. on Waste vs. Correlative Rights, p. 9). The examiners are of the opinion that prevention of waste, though our dominant concern, is not an exclusive one and must be balanced to at least some degree against other considerations of injury to the field in terms of damaging ultimate recovery prospects and harming correlative rights. "[In] carrying out this constitutional purpose [to conserve natural resources], the Commission must, as far as possible, act in consonance with the vested property rights of the individual." *Marrs v. Railroad Commission*, 177 S.W.2d 941, 948 (Tex. 1944).

BALANCING THE MANDATE

How Much Casinghead Gas is Necessary?

Although it is asserted by some parties that a generous daily casinghead gas limit is needed to *produce* tight oil trapped in the matrix of the reservoir, the more frequent reality seems to be that high casinghead gas production is necessary to *finance the operation* of oil wells which often might not even be drilled without a chance for the casinghead gas revenue. The operations of Baker & Taylor Drilling Company (Max Banks) are typical in this regard. In 1984 Mr. Banks purchased all

mineral rights (oil and gas) in two sections of land in northeastern Moore County and proceeded to drill six oil wells on one section and eight oil wells on the other, each formerly having one (abandoned) gas well only. Commission records show production in 1984 of 4513 barrels of oil and 53,111 mcf of casinghead gas, and in 1985 of 4600 barrels of oil and 380,678 mcf of casinghead gas. At the end of 1985, local gatherers notified Mr. Banks that they would for various reasons decline to take any more of his casinghead gas, and as a result he is now shut in. He testified that under a Section 103 new gas price of about $3.00 per mcf "it was a good economic play" as long as they were able to sell their casinghead gas without any problems, but that without this revenue the wells were not profitable and circumstances do not merit completion of any more oil wells. (Tr. 968, 976). Based on the production figures reported to the Commission (1985 oil production ledger data), the least GOR for the year of 1985 was 82,756:1, coming close to the cutoff for statutory gas wells. Mr. Banks testified that under these conditions he would "just drill and drill and drill" for oil. (Tr. 1028). But, as his vice-president for drilling contracts (Chester Lambert) subsequently testified, "You would have to have some casinghead gas to make these wells economical." (Tr. 1196 lines 19-20).

Hermann Oil & Gas Company, J. B. Hermann, operator, owns oil and gas rights on his Killough Lease in Hutchinson County. This lease is located within the traditional oil rim area and Mr. Hermann proceeded to drill 10 oil wells with good results, but found that Phillips Petroleum refused to take his casinghead gas. He asserted that he went to them before completing his no. 7 well and asked where he might perforate to their satisfaction, but after so completing they refused to take his gas anyway. Phillips did not put on any evidence to counter his allegation, but in fairness it must be noted

that Mr. Herrmann did not accurately report high perforations on his W-2 forms at all times. Cross-examination Exhibit 1 shows that such perfs at +290 to +320 in his Killough No. 2 well were not reported. When asked why he perforated this high and did not report it he conceded that the resulting gas was "probably not" necessary to lift oil from lower zones, but stated that "you need to have all of the intervals producing that will produce for an economical well." (Tr. 3107 line 2, Tr. 3105 lines 17-19).

Enron Oil and Gas Company has about 40,000 acres of land under lease between Dumas and Fritch in Moore and Potter Counties. Some 25 wells have been drilled under this lease, which conveyed oil rights only. Twelve of the wells failed to test a GOR below 100,000:1 and all are currently shut in due to lack of pipeline connection for their casinghead gas. Mr. Rex Howell, executive vice-president, testified that casinghead gas was the "principal value" in drilling decisions, not oil. (Tr. 3638 line 3). Some of the oil shows reported by Enron are for quite small amounts, such as 4 gallons and 1.2 gallons. (Tr. 3676 line 6, Tr. 3685 line 10).

GMC Company operates 16 oil wells in the traditional oil area of the field, with production from each averaging 3 BOPD. Frank Groce, geologist and part owner, testified that these and most wells in the oil column are only "marginally economically productive". (Tr. 2302 lines 2-3).

J. B. Watkins operates the Bell leases some eight miles southwest of Pampa with eight oil wells perforated in the Brown Dolomite. He agreed that casinghead gas revenue was critical to the economic feasibility of oil production.

> "I think that the drilling by the independents and the majors both will be substantially reduced if the amount of casinghead gas that you are allowed to sell is materially reduced . . . And if the GORs are

materially reduced, that's going to make the wells uneconomical to drill."
(Tr. 3904).

From a total of 9 wells on the leasts, Mr. Watkins has cumulative oil production of 17,000 barrels, with individual GORs ranging from 10,000:1 to 150,000:1. (Tr. 3843).

The Burnett Dixon Creek (6666) Ranch sponsored a study of production on their spread of some 110,000 acres in Carson and Hutchinson Counties, which is for the most part outside of the traditional oil area. Commencing around 1975 extensive exploration for oil, stimulated by rising crude prices, resulted in the completion of numerous wells. During the following ten years the producing oil well count rose from 468 to 832, with an increase in production as illustrated on Platt Exhibit 8. The examiners commend this exhibit to the Commissioners for special attention. It is clear from the production history graph that the natural decline curve from 1961 to 1971 was arrested by new oil well drilling on the ranch. These are high GOR wells, the 1985 average being 30,000:1. (Tr. 670 line 13). [Averages can be misleading, but in this case they are not. Analysis of Platt exhibit 25 shows that 67 out of 156 leases on the ranch have projected average per well recoveries below 10,000 barrels. GOR figures are reported for 57 of these wells with the *median* being about 37,500:1. The *median* reported GOR for all wells is about 27,000:1] Mr. Platt, consulting petroleum engineer for the ranch, testified that it was not necessary to exceed a GOR of 30,000:1 for technical reasons to recover these reserves (Tr. 670 line 25). The impetus for high gas production seems to stem rather from economic requirements. Platt Exhibit 26 illustrates the dilemma faced by one who is making a drill/no drill decision for typical oil well on the ranch; cumulative gas revenues are projected some three times higher than oil revenues; and seem to be required for eco-

nomic payout. There is no incentive to minimize GOR under these circumstances, but it cannot be disputed that these high GOR wells result in the production of oil which would not otherwise occur on a primary recovery basis.

Based on the evidence submitted by Mr. Platt the examiners recommend that the "Soule 5000' proposal (a 5000:1 casinghead gas limit applied against actual production rather than top allowable) not be incorporated into the field rules as a strict limit, but as a guideline only (see appendix 1).

It appears from the evidence that many small oil operators in the field require casinghead gas production to justify the search for oil in a field which has reached an advanced stage of depletion, with many wells making only two or three barrels of oil per day. The average oil rate for new wells on the Burnett Ranch is 5 BOPD (Platt Exhibit 26), a level which will not even attract the interest of one major operator:

> "In-house we have basically identified to meet minimum economics we need at least 30 barrels or about 30 barrels a day. With money the way it is right now management is not too interested in minimum economics. They want a little additional gravy thrown in the pot, basically."
> (Melissa Symmonds, Tenneco, Tr. 6742)

What was true for this major operator in 1986 was true for another in 1935. Skelly Oil Company Vice-President Mr. Stallcup, speaking of some of his new wells in a pressure depleted area:

> "Those five wells averaged 33 or 35 barrels per day . . . and, in my judgment, they will never pay unless we find some new method of cracking the oil."
> (Transcript page 144, Hearing of November 13, 1935, CIG Exhibit 1)

Although the major companies own substantial oil rights in the field, if Tenneco is typical it seems a safe assump-

tion that marginal economics requirements for all of the majors are higher than those for 15-well independents.

Field Rules as a Risk-Incentive Policy

Celeron submits that prospectors for remaining oil in the field should be "encourage(d) to take risks" with relaxation of perforation restrictions an appropriate measure in this regard. Some of the new wells in Moore County are not commercial for oil alone—a sample examined by Mr. Gillespie had average peak rate production of 7 BOPD with quick decline curves such that ultimate recovery would be limited to a range of 5000 to 7000 barrels per well. (Tr. 8490). In comparison, Ronnie Platt calculated that on the Burnett Ranch, a drill/no drill cutoff of 9000 barrels was required *with* a producing GOR of 30,000:1 for a commercially viable completion. (Platt Exhibit 26).

"Commercial" was defined by Mr. Gillespie as that which "would permit the recovery of the drilling and completion costs." (Tr. 8944) He further stated "I would say that if an operator could produce at least at a level that would recover the amount of lease operating expenses plus some profit, which would ordinarily be one to two barrels of oil per day per well, that that would be one of the tests for commerciality." (Tr. 9081). Mr. Gillespie was questioned by Counselor Sullivan and Examiner Osborn about Moore County oil economics as follows:

> Sullivan: But the stream of income that you're talking about in the instance of Moore County is just that; it's just the oil stream of income. Is that correct?
>
> Gillespie: "Yes. However, if one adds an increment of oil recovery—I mean, of gas recovery that would average 5,000 cubic feet per barrel over the life of the well, by my estimate one still would require on the order of slightly more than 20,000 bar-

rels of oil to recoup direct investment and operating expenses for that well.

If you add an increment over the life of the well of 10,000 cubic feet per barrel, 18,000 barrels or thereabouts would be required to recover the drilling, completion and operating expenses for the well."

Osborn: May I ask what prices you're using for oil and gas in your calculation, sir?

Gillespie: Yes, sir. $18 a barrel for crude oil, $1.25 for gas price, $200,0000 to drill and complete a well, $800 per well per month to operate, ten years for an estimated life, which is perhaps too short." (Tr. 8966-8967)

The issue was pressed by Pat Long, counselor for movants:

Long: I am interested in your scenario that if you are only producing a quarter of a barrel of oil out of zone A and a significant amount of gas, that you would recommend that that be plugged off. Could you tell me if that was done, how the oil that would be up there in whatever quantity would be produced?

Gillespie: It probably wouldn't be, because, in my judgment, there is so little oil there it is not commercial to recover, anyway. That would qualify as a resource, and in my understanding, there is a very, very big difference between the term resource and reserve. A *reserve* is a quantity that can be produced, under existing economic and technological circumstances. A *resource* is something that may be there but cannot be recovered under existing economic and technological circumstances. (Tr. 9100 line 21—9101 line 11, emphasis supplied).

* * *

Long: The problem I am having with substantial quantities, if we are interested in trying to maximize the total amount of hydrocarbons produced

from this field, wouldn't we perforate and produce zone A if it is recovering producible oil, regardless of the amount?

Gillespie: Not necessarily, no. If, for example, your question leaves the magnitude wide open and at 1/100 of a barrel of oil per day, the answer is absolutely no. If it were producing 100 barrels of oil per day, the answer is absolutely yes. (Tr. 9102 line 17—9103 line 1).

Dr. MacDonald, petroleum engineer for movants, supported perforation freedom and a high casinghead gas limit as an incentive to operators for completion of low volume oil wells.

MacDonald: "We're trying to encourage production here. Four barrels a day is a lot more than zero barrels a day. And if somebody can go out there and produce four barrels a day, I'm sure that anybody who goes out there and drills would like to get a lot more than that. But they are the risk takers.

What you're asking is that we don't allow people to take risks to recover hydrocarbons. We just say, 'We'll take care of you. Don't risk it.' And I feel we have to have people that are willing to risk. And if they go out there and don't hit the 60 barrels per day, but do hit 4 barrels per day, I think they should be allowed to produce them."

Schennkan: If they're making four barrels of oil and 350 mcf of gas per day, wouldn't you at least suspect, Dr. MacDonald, that they're probably producing significant quantities of gas that's not necessary for the production of oil?

MacDonald: You would have to take it on a case by case basis . . ." (Tr. 6604-6605)

Bill Murray, consultant for movants, similarly supported a high gas limit and perforation freedom as an economic inducement for completion of new oil wells:

Murray: "I'm talking about the incentive . . . prospectively to get these hundreds of billions (sic) of barrels of oil that we think we can get and to complete down as efficiently as possible." (Tr. 221)

* * *

Small: "Well, actually what you're giving on an incentive is in gas, not in oil?

Murray: I'm going to have the gas be the limiting factor . . . when I produce so much gas, it's however much oil I can produce up to that."
(Tr. 227)

* * *

Small: "You're asking the Commission to give certain incentives and to let oil operators have a bigger share of the gas, and that gas is obviously going to have to come from the gas that otherwise would be produced by the gas wells.

Now, how do you balance the rights where you're taking from one and giving to the other just as an incentive, an economic incentive to drill wells?"

Murray: "If it's accomplishing conservation. . . . It's a terrible situation to have the rights separated, but they exist that way, and I don't thing the Commission can just put their hands over their eyes and say 'We won't go after conservation because of this complex correlative rights problem'."
(Tr. 246-247)

Non-movants take a rather critical approach to this risk-incentive theory. Counselor Soule: "While they may not openly say so, the basic premise of the other side's case is to requset that the Commission give them gas which does not belong to them in order to make their otherwise uneconomical oil wells economical as a result of gas revenues." (Tr. 7024).

Regardless of one's philosophy on risk incentives, it is *particularly troublesome* to note that in 1986 some 27% of the casinghead gas in the field was being produced by

former LTX wells, which comprise only about 5% of the total oil wells in the field. (Tr. 5318 line 9, 5320, math: 500 divided by 10,796 = 4.6%). It is further troublesome to note that slightly over 70% of all casinghead gas in the field is being produced from 14.4% of the producing wells. (Tr. 8853). Special attention is directed to Appendix 3 for the proposition that excessive amounts of "casinghead gas" are being produced by some operators. If all were as it should be in the Panhandle Fields, the list of top 10 oil producers should correlate somewhat with the list of top 10 casinghead gas producers, indicating that produced casinghead gas was "indigenous to an oil stratum and produced from the stratum with oil" as required by Section 86.002(11) of the Texas Natural Resources Code. That Mr. Gordon Taylor, with 26 "oil" wells, should be producing more casinghead gas than Phillips Petroleum, with 654 oil wells, is a fact signalling some extremely aggressive "oil" completions in recent years. (Gillespie exhibits 63D-F set forth in Appendix 3). To permit such rapid and disorderly depletion of the remaining upper gas so as to econmically enable primary recovery of deeper oil would not be consistent with the § 86.097 requirement of the Texas Natural Resources Code. The new operators argue that without freedom from perforation restriction and ability to produce upper gas, the remaining oil will go unrecovered and thus be wasted. However, no primary recovery technique produces all reserves in place, and some of the oil left behind now may be recovered in future years when secondary recovery technology and product economics are more favorable. It is premature to condemn the producibility of remaining oil reserves in this field.

Conclusion

The examiners take the position that while encouragement of exploratory risk should be a goal of this Commission, it must be tempered by the peculiar nature of correlative rights conflicts in this field, which are specifi-

cally protected by a statute designed as a specific response to problems in this *field.* § 86.097 of the Natural Resources Code states in plan language: "No person in possession of or operating an oil well may produce from the oil well gas found in a horizon productive of gas only." Regardless of Commission policy goals, we are not free to disregard statutory law. Our Supreme Court has stated the rule:

> When the Legislature acts with respect to a particular matter, the administrative agency may not so act with respect to the matter as to nullify the Legislature's action even though the matter is within the agency's general regulatory field. There is little case law announcing the rule last stated, no doubt because it is self-evident.

State v. Jackson, 376 S.W.2d 341, 344-345 (Tex. 1964). In accord with this principle, the Texas Administrative Procedure Act states that courts shall reverse or remand any case in which "the administrative findings, inferences, conclusions or decisions are in violation of constitutional or statutory provisions." TEX. REV. CIV. STAT. ANN. art 6252-13a 19(e)(1) (Vernon Supp. 1987). We are bound by the Natural Resources Code to retain the historic Panhandle Field Rules prohibition against completion of oil wells in a dry gas horizon.

OTHER PROBLEMS

Reporting of Natural Gas Liquids

Some gas wells in the Panhandle produce very small amounts of liauid condensate byproducts commonly referred to as "drip".

> "In our country in the early '50s, the common thing was that everybody in the general area burned the drip. They knew where all the drips were, and they burned it in their car." (Max. Banks, Tr. 962).

In recent years the Commission has received complaints that some gas wells are making excessive condensate which is either produced to the plant without separation, or separated on the lease and moved secretively to Oklahoma for blending with crude oil (unsworn testimony of L. C. Shelton).

In response to complaints by a group which Ron Slover organized, the Commission in 1985 performed tests on 71 West Panhandle field gas wells and found that the wells produced on average slightly more than ½ gallon of condensate per day, or about ⅓ barrel per month. Mr. Slover appeared at this hearing to press his case for a Commission requirement that separators be required on all gas wells, but stated in unsworn testimony that he had not even asked to see the report which the Commission went to so much trouble to generate upon his complaint! (Tr. 935). His criticism: "most of those tested were conducted during the summer (and) . . . the so-called separators which were used were not of sufficient capacity to separate the liquid hydrocarbons from the gas." (Tr. 934). The record reflects a number of winter tests, as Mr. Slover would have seen had he ordered a copy of the District 10 report.

In June of 1986 the cumulative total of all liquids produced from some 3500 active gas wells was approximately 100 barrels. (Tr. 5140). J. B. Herrmann, operator witness for movants, operates about 10 gas wells and testified that none of them produced a sufficient amount of liquids to merit installation of separation equipment. (Tr. 3094-3095). He stated that the custom in the field was to remove these liquids instead with drips on the gathering lines. (Tr. 3095). J. B. Watkins, another operator witness for movants, also operates gas wells and likewise has no separators on them. (Tr. 3951). He stated that he thought it might be necessary to operate separators on wells in some areas of the field, but when questioned on this could not name any such area or wells. (Tr. 3951).

Miles Reynolds, chemical and petroleum engineer witness for movants, testified that most Panhandle Field gas must be boosted to buck transmission line pressure and any entrained liquids not removed before hand would damage transmission equipment.

> Q. "Is it common to find an inlet scrubber before the compressors to remove any liquids before the well stream—gas stream reaches the compressor?
>
> A: Yes. That's a fairly standard piece of equipment.
>
> Q: What would happen if liquids were entrained in that gas at the time it reached the compressor?
>
> A: It would be trapped by such a device. That's the purpose of it.
>
> Q: Would it cause damage to the compressor if liquids reached the compressor?
>
> A: Yes. Oh, very definitely." (Tr. 6063-6064)

The examiners suspect that human nature will assert itself in continued suspicions regarding gas well separation equipment. We suggest that as in the past, these complaints be referred to the District 10 office for processing.

Undercover Removal of Natural Gas Liquids

L. C. Shelton, in unsworn testimony, stated that some operators were secretively removing gas condensate liquids from their leases and transporting them across the Oklahoma line for blending with crude oil as a stabilizing agent.

In 1983 the Texas Legislature enacted Chapter 114 of the Natural Resources Code concerning regulation of trucks carrying liquid hydrocarbons. All such transporters are required to carry a cargo manifest identifying source and amount of volumes collected, including lease name, operator name, quantity removed, time loaded, and

intended point of destination including the name of the receiving facility. The law provides:

> "The Commission, its designated agents or employees, or a peace officer may examine a cargo manifest, whether it is on an oil tanker vehicle or in the records of the transporter, under circumstances where the examination is a lawful attempt to determine whether this chapter is being violated."
> V.T.C.A. Natural Resources Code § 114.101

Falsification of a cargo document is a criminal offense.

If Mr. Shelton or others in the field observe practices of this nature they consider suspicious, they should make a written report on the District 10 office with a copy to the local sheriff or deputy in charge of the area. This report should include a full description of the incident with license plate number or RRC number of the gathering vehicle, and specifically request a Section 114 Tex. Nat. Res. Code (Statewide Rule 85) investigation.

Daily Casinghead Gas Limit

The examiners recommend that the daily casinghead gas limit be readjusted. The limit has been changed on three prior occasions to reflect differing production rates and ratios, and it seems now proper to adjust it again. The last change was in 1941, when the limit was lowered from 775 mcf/d to 500 mcf/d. (CIG Exhibit 6 tab 52). The examiners believe a limit of 120 mcf/d as proposed in the notice of hearing is now appropriate and should be enacted. This figure is calculated by application of the normal Statewide multiplier of 2000:1 against the top allowable of 60 barrels of oil per day, which results in a daily casinghead gas limit of 120 mcf per well. Ronnie Platt, engineer for the Burnett Ranch interests, movants, stated.

> "I believe there's no question that it [his recovery forecast] could be obtained with the existing 500 gas

> limit under the existing rules, but I believe that the operators could probably achieve these same results or very close to these results with the gas limit as proposed by the Commission in their notice of hearing." (Tr. 553)

The Burnett Ranch interests have some 110,000 acres of oil *and* gas rights. In the eyes of the examiners, this factor tends to give Mr. Platt's testimony some measure of impartiality or neutrality on the issue of daily gas limits.

J. B. Watkins testified that a 120 mcf/day limit would not affect any of his existing wells. (Tr. 3990). Clark Gillespie analyzed some 11,000 W-10 filings and determined that 95% of the individual oil wells reported daily casinghead gas capacity at or below 120 mcfd. (Tr. 8810). This leaves some 500 to 600 wells above the proposed limit on an individual basis, but if lease averaging is permitted to continue, many of these will be unaffected. Dr. MacDonald testified that a reduction in casinghead gas production would have an exactly proportional reductionate effect on liquids production. (Tr. 6367). No evidence or test results were submitted in support of this assertion, and the examiners firmly disagree with the conclusion. We suggest that placing a high casinghead gas producing well on a time clock to give intermittent production will allow the wellbore time to load up with fluids between cycles and minimize excess casinghead gas production. Alternatively, cycling or re-injection of excess casinghead gas should be considered if production of over 120 mcfd/well is absolutely necessary for the recovery of oil. (Tr. 8846). The oil portion of this reservoir is in an advanced stage of depletion. A reduction in casinghead gas withdraws *and* a reduction of gas well gas withdrawals from zones below or within the gas-oil contact or transition zone will prolong the producing life of the oil field and add to recoverable reserves.

FINDINGS OF FACT

1. The proceedings in this docket were duly initiated pursuant to a notice issued January 9, 1986 by the Railroad Commission of Texas, and all affected operators received notice of the same as required by the Commission's Rules of Practice and Procedure and by the Administrative Procedure and Texas Register Act.

2. All persons seeking to become parties to this proceeding were given the opportunity to file a statement and argue on behalf of their request to be named as a party.

3. The proceedings in this docket and the hearing and record thereof are properly before the Railroad Commission of Texas.

4. A prehearing conference was held in this case on December 18, 1986, and proceedings to present evidence commenced on January 6, 1987.

5. The Railroad Commission called this hearing to review existing rules and to consider adopting new or amended rules for the Panhandle Carson County Field; Panhandle Collingsworth County Field; Panhandle Potter County Field; Panhandle Gray County Field; Panhandle Hutchinson County Field; Panhandle Moore County Field; Panhandle Wheeler County Field; Panhandle West (Sanford) Field; Panhandle West (Tubbs) Field; Panhandle (Osborne Area) Field; Panhandle, East (Albany Dolomite, Lower) Field; Panhandle, West Field; and Panhandle, East Field in Carson, Collingsworth, Gray, Hutchinson, Moore, Wheeler, Potter, Oldham, Sherman, and Hartley Counties in Texas. These fields collectively are referred to as the Panhandle Fields.

6. The Panhandle Carson County Field; Panhandle Collingsworth County Field; Panhandle Potter County

Field; Panhandle Gray County Field; Panhandle Moore County Field; Panhandle (Osborne Area) Field and Panhandle Wheeler County Field are designated by the Commission as oil fields.

The Panhandle, West (Sanford) Field; the Panhandle, West (Tubbs) Field; the Panhandle, East (Albany Dolomite, Lower) Field; the Panhandle, West Field; and the Panhandle, East Field are designated by the Commission as gas fields.

7. The Panhandle Oil Field (by various county designations) has been regulated as a separate field under special rules promulgated in orders pricipally adopted during the 1930s and 1940s. Most of the basic special field rules are set forth in Division Two of Oil and Gas Circular 16-B (October 17, 1933), special Order Fixing Allowable Production of Sweet and Sour Natural Gas in the Panhandle District of Texas (December 10, 1935), Order No. 20-169 (November 18, 1937), and Order No. 10-3087 (November 13, 1941). (Tr. CIG Exhibit 6, Tab 15, Tab 28, Tab 35, and Tab 53; Stumpf Exhibits 9A and 9B.)

   The West Panhandle Gas Field and East Panhandle Gas Field have been regulated as separate non-associated gas fields under special rules promulgated in various orders entered from the late 1940s through the early 1950s. (Tr. CIG Exhibit 6, Tab 28, Oil and Gas Docket No. 108 [December 10, 1935]; Stumpf Exhibits 9A and 9B.)

8. The discovery oil well in the Panhandle Field was the Gulf Production Company S. B. Burnett No. 2 well in Carson County. This well was drilled in 1920 and completed in 1921 with an initial pumping potential of 175 barrels per day. (Tr. 286-287; Stumpf Exhibit 4).

   The discovery gas well in the Panhandle Field was the Canadian River Gas Company Masterson No. 1

well in Potter County, now known as the Colorado Interstate Gas Company Masterson C-1 well. This well was drilled in 1917 and completed in 1918 with an initial potential of 4.8 million cubic feet of gas. (Tr. 283-285; Stumpf Exhibit 3).

9. In mid-1986 there were approximately 10,796 producing oil wells and 3510 producing gas wells in the fields. Cumulative production to that point was approximately 1.245 billion barrels of oil, 6.4 trillion cubic feet of casinghead gas and 31 trillion cubic feet of gas well gas. (Johnston Exhibit 11, Johnston Exhibit 5, Tr. 6424, Gillespie Exhibit 10).

10. Remaining producible oil reserves total at least 100 million barrels with current primary recovery technology. There is a substantial additional amount of oil in place not commercially producible under current primary recovery technology and economic conditions. (Gillespie Exhibit 5).

    Remaining gas well gas reserves are approximately 2.8 trillion cubic feet. (Gillespie Exhibit 10).

11. Five separately identifiable geologic rock formations may be encountered in the Panhandle Fields: The Brown Dolomite, the Moore County Lime, the Arkosic Dolomite, the Granite Wash, and the Granite or Basement (sometimes called Fractured Granite or Weathered Granite). (Tr. 7042-7043, 2268, 4029-4030, 7957.) These formations are sometimes segregated by impermeable shale barriers, but are interconnected and pressure communicated at various points in the field. (Tr. 7964, 7829, 7385, 7389, 7442, 7494, 9076.) (Tr. 9076; CIG Exhibit 6, Tab 28, Oil and Gas Docket No. 108, p. 1 [December 10, 1935], Holmes Exhibit 3.)

12. The Brown Dolomite and in certain regional areas, the Moore County Lime are blanket formations containing potentially productive porosity intervals of

5% or greater extending laterally over wide distances. (Tr. 7064-7065, 7664, 7671, 7677, 7682; Bay Exhibits 72-78.) Panhandle Field formations lying below the Brown Dolomite are more erratic, and porosity distribution within those lower formations tends to be local and discontinuous. (Tr. 7062, 7444-7445, 7549-7551.)

13. Most of the oil development and production from the Panhandle Field comes from the northeastern flank of the field, where there is a heavy concentration of oil wells. There are scattered pockets of oil reserves in the remainder of the field, generally found in structural depressions and traps. (Tr. 7078-7080; Bay Exhibit 11.)

14. The upper zones of the Panhandle Fields generally produce only gas, while oil, if present at any depth, is usually found at or below 250 feet above sea level. (Tr. 8582, 8600, 8658, 9200, 3700, 7386-7388, Gillespie Exhibits 32 and 33; CIG Exhibit 1, Oil and Gas Docket No. 108, *et al.*, p. 355 [November 19, 1935]; CIG Exhibit 5, Bauer, Oil and Gas Fields of the Texas Panhandle, 10 BULL. OF AM. ASSOC. OF PET. GEOLOGISTS 733, 744 [August 1926]; CIG Exhibit 5, Cotner & Crum, *Geology and Occurrence of Natural Gas in Amarillo District, Texas,* 17 BULL. OF AM. ASSOC. OF PET. GEOLOGISTS 877, 886 [August 1933]; Moore County Royalty Owners Assoc. Cross-Examination Exhibit 4; Rogatz, *Geology of Texas Panhandle Oil and Gas Field,* 23 BULL. OF AM. ASSOC. OF PET. GEOLOGISTS 983, 986 [July 1939]; Herrmann Cross-Examination Exhibit 3; Hagy, *History of Development of General Geology of the Panhandle Field of Texas,* 12 PANHANDLE-PLAINS HISTORICAL REVIEW, p. 7 [1939].)

15. Operators can generally use information from drillers' logs, producing characteristics of surrounding

wells, selective tests of isolated intervals within the wellbore, wireline logs, core analyses, and geological samples, in addition to reference to structure and stratigraphy, in order to determine the gas-oil contact in an individual oil well. (Tr. 1120, 2322, 2939, 3173, 3660-3661, 4115-4116, 2939, 2218, 2324, 2460, 4021, 5046, 9104, 9106, 197, 8549-8550, 4115, 1129, 7920-7921, 3832, 2445, 2457, 4115-4116, 4130, 1182, 9091, 2322, 2622.)

16. Operators can avoid perforation of oil wells at horizons which produce only gas and can thereby maintain a low gas-oil ratio and/or low casinghead gas rate. (Tr. 5987, lines 1-8; 9008, line 21, line 6; 9070, lines 1-12; 8853; 6952, lines 9-14; Gillespie Exhibit 66; CIG Exhibit 1, Oil and Gas Docket No. 10-1322, pp. 175-176 [March 20, 1940].)

17. It is not physically necessary to perforate oil wells in upper gas-only intervals in order to recover deeper oil. (Tr. 8989-8990, 3425, 8737, 8868-8869; Gillespie Exhibit 54A.)

18. Production of gas from above oil in immediate proximity in an oil well dissipates reservoir energy thereby reducing ultimate recovery of oil and causing waste. (Tr. 8433, lines 15-20; 3695, lines 9-22; 9079, lines 11-15; 6377, line 21—p. 6378, line 5; Strickland Exhibit 18; CIG Exhibit 1, Oil and Gas Docket No. 108, *et al.*, pp. 115-116 [July 18, 1935]; Oil and Gas Docket No. 108, *et al.*, p. 140 [November 19, 1935]; Gillespie Exhibit 50, *Texas Panhandle Fields: A Study of Gas Wastage and the Feasibility of Returning Waste Gas to Reservoir*, p. 19 [August 1934]; CIG Exhibit 6, Tab 28, Oil and Gas Docket No. 108, pp. 4-5 [December 10, 1935]; CIG Exhibit 6, Tab 75, Oil and Gas Docket No. 10-36,290 [September 16, 1957].)

19. West and East Panhandle Field gas wells generally produce from higher gas-only intervals separated in some areas by shale barriers from any oil-productive intervals at the sites of the gas wells and/or are completed at some lateral distance from any oil-bearing porosity interval, and therefore for the most part do not withdraw reservoir energy necessary for production of oil. (Tr. 8958; 6986, lines 14-19; 8426-8431; Strickland Exhibits 17 and 18.)

20. Production of unnecessary upper gas interval gas through Panhandle Field oil wells drains reserves which properly lie within the assigned proration units of West and East Panhandle Field gas wells. (Tr. 8775, 8778-8779, 8788, lines 14-17, 6995, lines 10-21; Gillespie Exhibits 51, 56, 58-63c.)

21. Completion of oil wells below the dry gas interval in the oil-productive portion of the Panhandle Fields reservoir(s) causes oil wells and gas wells to drain different underground pore space and minimizes competition for the same hydrocarbons on overlapping oil and gas surface proration units. (Tr. 6908, lines 3-10.)

    More than 15,000 oil wells and gas wells have been drilled and are now producing under the Railroad Commission's regulatory system of assigning the same surface acreage to both oil wells and gas wells. (Tr. 2878, lines 9-18; 6908, lines 3-10.)

22. The Commission has zoned the Panhandle Field reservoir(s) into separate gas fields and oil fields. Commission field rules require that an oil well be perforated only in levels, sands or strata productive of oil. (Commission Docket 108 Order, December 10, 1935, CIG Exhibit 1).

23. In 1956, all operators in the field were notified by the Commission that perforation of an oil well "in

the dry gas zone" was "definitely in violation" of Railroad Commission rules. (Murray Cross-examination Exhibit 1).

24. Tex. Nat. Res. Code § 86.097 states:

    "No person in possession of or operating an oil well may produce from the oil well gas found in a horizon productive of gas only."

    This statute was enacted by the Legislature as a part of H.B. 266 on May 1, 1935, in *specific response* to abusive practices in the Panhandle Fields. (Act of May 1, 1935, ch. 120, 1935, Tex. Gen. and Spec. Laws 318; Commission Docket 108 order, December 10, 1935, CIG Exhibit 1.)

25. Gas well gas produced from the Panhandle Fields generally contains an insufficient amount of entrained liquid to justify installation of separating devices. (Tr. 6063, line 12—6064, line 4; 4932; Slover Cross-Examination Exhibit 1.)

26. West Panhandle Field gas wells efficiently drain 640-acre proration units. (Tr. 8519, lines 12—8520, line 2; 6180, lines 9-12; 6778, lines 13-16; Gillespie Exhibit 11A-11E, 12, 13, 13A.))

27. A daily casinghead gas limit of 120 mcf per well as proposed in the hearing notice is calculated by multiplication of the statewide 2000:1 figure against the top field allowable of 60 barrels of oil per day. 95% of all oil wells in the field report daily casinghead gas capacity below 120 mcf, without benefit of lease averaging. (Tr. 8810).

28. New drilling of oil between 1978 and 1985 arrested a 20 year decline curve and resulted in the additional recovery of at least 20 million barrels of oil which probably would not have been recovered otherwise. Casinghead gas production from the field ap-

proximately doubled during this interval. (Johnston Exhibits 2 and 10, Tr. 5129).

29. Some 27% of the casinghead gas being produced in the field is coming from former LTX wells. 71.1% of all casinghead gas is being produced from some 14.4% of the oil wells in the field. (Tr. 5318, 8853).

30. Some oil operators are maximizing casinghead gas production for economic reasons by perforating up into gas only horizons. (Tr. 1196, 3105, 3107, 3638, 3904).

31. Since the enactment of comprehensive field rules in 1935, technological advances have radically changed wellbore completion techniques and analytical methodology. (Tr. 3917-3919, CIG Exhibit 1, May 11, 1936, p. 259; Gillespie Exhibit 27, Bay Cross-examination Exhibits 6, 20 and 25, Podzemny Exhibit 1).

CONCLUSIONS OF LAW

1. All action has been taken and all prerequisites fulfilled to invest the Railroad Commission with jurisdiction to decide this matter.

2. Sections 85.201, 85.202(b) and 86.081(a) of the Texas Natural Resources Code charge the Commission with the duty to regulate production of oil and gas in order to prevent waste and protect correlalative rights.

3. When faced with a conflict between its mandates of preventing waste and protecting correlative rights, the Commission is required to balance all competing considerations in resolution of the matter. The prevention of waste is to be weighted heavily in this balancing process as it is the primary goal of the Commission.

   Gulf Land Co. v. Atlantic Refining Co., 131 S.W.2d 73 (Tex. 1939).

Hawkins et al. v. Texas Co., 209 S.W.2d 338 (Tex. 1948).

Phillips Petroleum Company et al. v. American Trading and Production Corporation et al., 361 S.W.2d 942 (Tex. Civ. App.—El Paso 1962, writ ref'd n.r.e.).

Railroad Commission v. Manziel, 361 S.W.2d 560 (Tex. 1962)

Texaco, Inc. v. Railroad Commission, 583 S.W.2d 307 (Tex. 1979)

Railroad Commission of Texas v. Fain, 161 S.W.2d 498 (Tex. Civ. App.—Austin 1942, writ ref'd w.o.m.)

Marrs v. Railroad Commission, 177 S.W.2d 941 (Tex. 1944)

4. Section 86.095 of the Texas Natural Resources Code authorized the Commission to zone the Panhandle Field reservoir(s) into two separate fields, to which the same tract of surface acreage may be assigned. Such dual assignment of acreage should be continued in order to prevent widespread disruption of correlative rights.

5. Section 86.097 of the Texas Natural Resources Code prohibits the completion and perforation of Panhandle Field oil wells at horizons which are productive only of gas.

6. Section 86.012(a)(11) of the Texas Natural Resources Code defines waste to include "the production of natural gas from a well producing oil from a stratum other than that in which the oil is found" unless produced in a separate string of casing. TEX. NAT. RES. CODE ANN. § 86.012(a)(11) (Vernon Supp. 1986).

7. "Casinghead gas" is defined at Section 86.002(11) of the Texas Natural Resources Code as "any gas or vapor indigenous to an oil stratum and produced

from the stratum with oil." TEX. NAT. RES. CODE ANN. §86.002(11) (Vernon Supp. 1986).

8. The Railroad Commission must follow and enforce the provisions of the Texas Natural Resources Code. *State v. Jackson*, 376 S.W.2d 341, 344-345 (Tex. 1964); TEX. REV. CIV. STAT. ANN. art. 6252-13a § 19(e)(1) (Vernon Supp. 1987).

9. Appendix 1 to the Proposal for Decision is a guideline which establishes a rebuttable presumption that a qualified well is properly completed.

10. Charges and clarifications of rules in the Panhandle Fields are appropriate in light of "changed conditions", *Railroad Commission v. Aluminum Company of America*, 380 S.W.2d 599 (Tex. 1964).

11. Adoption of the proposed order is a conservation measure that is necessary to prevent waste and to protect correlative rights in the subject fields.

EXAMINERS' RECOMMENDATION

Based on the foregoing findings of fact and conclusions of law, the undersigned examiners recommend that the attached order be adopted by the Commission. This order restates the rule that perforation of oil wells in dry gas horizons is not permitted, reduces the daily casinghead gas limit to 120 mcf per well, consolidates various minor fields, and rescinds numerous obsolete orders.

Respectfully submitted,

/s/ George Singletary
GEORGE SINGLETARY
Senior Technical Examiner

/s/ William Osborn
WILLIAM OSBORN
Legal Examiner

WO:GS:bb:W25

RAILROAD COMMISSION OF TEXAS
OIL AND GAS DIVISION

OIL AND GAS DOCKET NO. 10-87,017

FINAL ORDER ADOPTING AND CLARIFYING RULES AND REGULATIONS FOR THE PANHANDLE CARSON COUNTY FIELD, PANHANDLE COLLINGSWORTH COUNTY FIELD, PANHANDLE POTTER COUNTY FIELD, PANHANDLE GRAY COUNTY FIELD, PANHANDLE MOORE COUNTY FIELD, PANHANDLE WHEELER COUNTY FIELD, PANHANDLE HUTCHINSON COUNTY FIELD, PANHANDLE, WEST (SANFORD), PANHANDLE, WEST (TUBBS), PANHANDLE (OSBORNE AREA), PANHANDLE, EAST (ALBANY DOLOMITE, LOWER) FIELDS, PANHANDLE, WEST FIELD AND PANHANDLE, EAST FIELD, HEREINAFTER REFERRED TO AS THE "PANHANDLE FIELDS".

The Commission finds that, after statutory notice in the above-numbered docket, the presiding examiners have made and filed a proposal for decision containing findings of fact and conclusions of law, which was served on all parties of record; and that this proceeding was duly submitted to the Railroad Commission of Texas at conference held in its offices in Austin, Texas.

It has come to the Commission's attention that confusion exists among some operators in the Panhandle Fields as to the applicability of the rules presently enforced by the Commission in the administration of oil and gas conservation matters in said fields, and more particularly in the methods of completion permitted for oil wells. So that the existing confusion may be eliminated, the Commission, after review and due considera-

tion of a Proposal For Decision in Docket No. 10-87,017 and the findings of fact and conclusions of law contained therein, hereby adopts as its own the findings of fact and conclusions of law as if fully set out and separately stated herein.

Therefore, IT IS ORDERED by the Railroad Commission of Texas that the historic classification and separation of Panhandle oil and Panhandle gas fields shall be retained; that the following fields shall be consolidated:

Panhandle East (Albany Dolomite, Lower) into Panhandle, East Gas

Panhandle, West (Sanford) into Panhandle, West Gas

Panhandle, West (Tubbs) into Panhandle (Red Cave)

Panhandle (Osborne Area) into Panhandle Wheeler County Oil;

that various obsolete docket 108 and other orders as listed below be rescinded; and that the following rules, in addition to such of the Commission's general rules and regulations as are not in conflict herewith, be and the same are hereby clarified and adopted to govern the drilling, completion and operation of wells in the Panhandle Fields:

Oil Field Rules

Rule 1. Panhandle Field oil wells are restricted to completion in horizons bearing producible oil, production from said horizons to be capable of passing a gas-oil ratio cutoff of 100,000:1 on isolated 72 hour test of the highest 50 feet perforated. No person in possession of or operating an oil well may produce from the oil well gas found in a horizon productive of gas only.

Rule 2. No oil well shall hereafter be drilled nearer than FOUR HUNDRED AND SIXTY SEVEN (467) feet to any well completed in or drilling

to the same reservoir on the same lease, unitized tract, or farm; and no well shall be drilled nearer than TWO HUNDRED AND THIRTY THREE (233) feet to any property line, lease line, or subdivision line; provided, however, that the Commission will, in order to prevent waste or to prevent the confiscation of property, grant exceptions to permit drilling within shorter distances than herein prescribed, whenever the Commission shall have determined that such exceptions are necessary either to prevent waste or to prevent the confiscation of property. When exception to this rule is desired, application therefor shall be filed and will be acted upon in accordance with the provisions of Commission Statewide Rules 37 and 38, which applicable provisions are incorporated herein by reference.

The aforementioned distances in the above rule are minimum distances to allow an operator flexibility in locating a well; and the above spacing rule and the other rules to follow are for the purpose of permitting only one well to each proration unit.

In applying this rule, the general order of the Commission with relation to the subdivision of property shall be observed.

Rule 3. The acreage assigned to the individual oil well for the purpose of allocating allowable oil production thereto shall be known as the prescribed proration unit. No proration unit shall consist of more than TWENTY (20) acres except as hereinafter provided, and the two farthermost points in any proration unit shall not be in excess of ONE THOUSAND FIVE HUNDRED (1500) feet removed from each other, provided, however, that in the case of long and narrow

leases or in cases where because of the shape of the lease such is necessary to permit the utilization of tolerance acreage, the Commission may, after proper showing, grant exceptions to the limitations as to the shape of the proration units as herein contained. All proration units, however, shall consist of continuous and contiguous acreage which can reasonably be considered to be productive of oil.

If after the drilling of the last well on any lease and the assignment of acreage to each well thereon in accordance with the regulations of the Commission there remains an additional unassigned lease acreage of less than TWENTY (20) acres, then and in such event the remaining unasigned lease acreage up to and including a total of FIVE (5) acres may be assigned to the last well drilled on such lease, or may be distributed among any group of wells located thereon, so long as the proration units resulting from the inclusion of such additional acreage meets the limitations prescribed by the Commission.

An operator, at his option, shall be permitted to form fractional units of TEN (10) acres, with a proportional acreage allowable credit for a well on such unit, with the two furthermost points of such TEN (10) acre fractional unit not greater than ONE THOUSAND ONE HUNDRED (1100) feet removed from each other.

An operator, at his option, shall be permitted to form fractional units of FIVE (5) acres, with a proportional acreage allowable credit for a well on such unit, with the two farthermost points of such FIVE (5) acre fractional unit not greater than SEVEN HUNDRED FIFTY (750) feet removed from each other.

Operators shall file with the Commission certified plats of their properties in said field, which plats shall set out distinctly all of those things pertinent to the determination of the acreage credit claimed for each well unless such filing has already been made; provided that it the acreage to any proration unit has been pooled, the operator shall furnish the Commission with such proof as it may require as evidence that interests in and under such proration unit have been so pooled.

Rule 4. The top allowable for oil wells is set to be 60 barrels of oil per day (BOPD). The maximum daily oil allowable for each well shall be based 25% on acreage and 75% per well and will be equal to the summation of Twenty-five percent (25%) of top allowable multiplied by the ratio the number of acres assigned to the well bears to twenty (20) acres plus seventy-five percent (75%) of top allowable; thus, each well assigned twenty (20) acres will have a 60 BOPD allowable, each well assigned ten (10 acres will have a 53 BOPD allowable, and each well assigned five (5) acres will have a 49 BOPD allowable.

Rule 5. An oil well shall be allowed to produce a daily maximum of 120 mcf of casinghead gas when assigned 20 acres, 106 mcf of casinghead gas when assigned 10 acres, and 98 mcf of casinghead gas when assigned 5 acres.

Rule 6. Individual oil wells shall be tested annually on a schedule beginning in April and concluding in August. Operators will be advised of their test periods and procedures by the District 10 office.

Gas Field Rules

Rule 1. The division and boundary line between the Panhandle, East and Panhandle, West gas fields as set forth in docket 10-23,955 is retained.

Rule 2. No gas well in the Panhandle, West, field shall hereafter be drilled nearer than SIX HUNDRED SIXTY (660) feet to an well completed in or drilled to the same reservoir on the same lease, unitized tract or farm, and no well shall be drilled nearer than THREE HUNDRED THIRTY (330) feet to any property line, lease line or subdivision line; No gas well in the Panhandle, East field shall hereafter be drilled nearer than SIX HUNDRED SIXTY (660) feet to an well completed in or drilled to the same reservoir on the same lease, unitized tract or farm, and no well shall be drilled nearer than THREE HUNDRED THIRTY (330) feet to any property line, lease line or subdivision line;

Provided, however, that the Commission will, in order to prevent waste or to prevent the confiscation of property, grant exceptions to permit drilling within shorter distances than herein prescribed, whenever the Commission shall have determined that such exceptions are necessary either to prevent waste or to prevent the confiscation of property. When exception to this rule is desired, application therefor shall be filed and will be acted upon in accordance with the provisions of Commission Statewide Rules 37 and 38, which applicable provisions are incorporated herein by reference.

The aforementioned distances in the above rule are minimum distances to allow an operator flexibility in locating a well; and the above spacing rule and the other rules to follow are for the

purpose of permitting only one well to each proration unit.

In applying this rule, the general order of the Commission with relation to the subdivision of property shall be observed.

Rule 3. The acreage assigned an individual non-associated gas well for the purpose of allocating allowable gas production thereto shall be known as a gas proration unit, and such acreage may be claimed for each non-associated gas reservoir independently of any other reservoir. No gas proration unit shall contain more than SIX HUNDRED FORTY (640) acres in the Panhandle, West field, or ONE HUNDRED SIXTY (160) acres in the Panhandle, East field except as hereinafter provided; and no such acreage shall be included in any proration unit formed or created subsequent to the effective date of this order and allocated to the well thereon unless the farthermost two points of the unit created by the inclusion of such acreage be not greater than EIGHT THOUSAND FIVE HUNDRED (8500) feet in the Panhandle, West field and FOUR THOUSAND FIVE HUNDRED (4500) feet in the Panhandle, East field; provided that tolerance acreage of ten percent (10%) shall be allowed for each unit so that an amount not to exceed a maximum of SEVEN HUNDRED FOUR (704) acres in the Panhandle, West field and ONE HUNDRED SEVENTY SIX (176) acres in the Panhandle, East field may be assigned, and each unit containing less than SIX HUNDRED (640) acres in the Panhandle, West field or ONE HUNDRED SIXTY (160) acres in the Panhandle, East field shall be a fractional proration unit.

All such proration units shall consist of continous and contiguous acreage which can reasonably be considered to be productive of gas.

Operators shall file with the Commission certified plats of their properties in said field, which plats shall set out distinctly all of those things pertinent to the determination of the acreage credit claimed for each well unless such filing has already been made; provided that if the acreage assigned to any proration unit has been pooled, the operator shall furnish the Commission with such proof as it may require as evidence that interests in and under such proration unit have been so pooled.

Rule 4: The daily allowable production of gas from individual gas wells completed in the Panhandle, West and East gas fields, shall be determined by allocating the allowable production, after deductions have been made for wells which are incapable of producing their gas allowables, among the individual wells in the following manner:

Ninety-five percent (95%) of the total field allowable for each field shall be allocated among the individual wells in the proportion that the acreage assigned such well for allowable purposes bears to the summation of the acreage with respect to all proratable wells producing from the respective field.

Five percent (5%) of the total field allowable for each field shall be allocated among the individual wells in the proportion that the deliverability of such well, as evidenced by the most recent test filed to the Railroad Commission, bears to the summation of the deliverability of

all proratable wells producing from the respective field.

Rule 5. Separating devices are not required for gas wells completed in dry gas (gas only) horizons. On-lease separating devices (prior to metering) are required where gas wells are completed to depths productive of oil, or in any case where on-lease separating devices would recover over 12 barrels per year of condensate or hydrocarbon liquid. On-lease drip collectors or interceptors are permissible separating devices if all products separated are accurately reported in compliance with Statewide Rule 85 when removed from the lease. All condensate or hydrocarbon liquid production over 1 barrel per gas well per month recovered on the lease must be reported on the monthly production report.

Rule 6. Gas wells in the Panhandle, West field shall be tested in June, July and August of each year, with reports due September first. No test is required of gas wells in the Panhandle, East Field due to extremely low reservoir pressure.

Gas well test data shall be filed using forms G-1 and G-10 rather than forms G-10 and G-11.

General Rules

Existing and future oil wells meeting one of the criteria set forth in Appendix One to the Proposal For Decision in this docket will be presumed to have been properly completed. Operators shall have a period of one year to bring existing wells into compliance with Appendix One guidelines.

All operators electing to complete a new oil well or add perforations to an existing well such that no Appendix One guideline is met must make such note on their W-2

filing and attach for the Central Records well file a summary of selective test data or other analysis supporting their completion as in a horizon productive of oil, and shall indicate that the District Office was notified prior to testing and indicate whether or not testing was witnessed by the District Office.

Existing gas wells will be presumed to have been properly completed if they are no deeper than +250 feet (sea level datum), or the base of the Brown Dolomite, whichever is higher; except in the Appendix One Section Four areas where proper completion is presumed if above the higher of the base of the Brown Dlomite, or +350 or +450 feet (set level datum) in areas 4(a) and (b) respectively. Operators shall have a period of one year to bring existing wells into compliance with these guidelines. All operators electing to complete a new gas well to a depth lower than presumed proper or deepen an existing gas well below that depth must make such note on their G-1 filing and attach for the Central Records well file a summary of selective test data or other analysis supporting their completion as in a horizon productive of dry gas or gas only, and shall indicate that the District Office was notified prior to testing and indicate whether or not testing was witnessed by the District Office.

These requirements and guidelines are based on a Commission finding that gravity segregation of oil and gas in the Panhandle fields was generally efficient over geologic time such that in locations where there is both producible oil and free gas, the two are generally divided and separated according to their densities into lower oil intervals and upper gas intervals. For this reason, dual assignment of the same surface acreage to both the oil and the gas fields for recovery from two properly completed and classified wells, one for recovery of oil and the other for recovery of gas, shall be permitted to continue as it has since the inception of comprehensive field rules in 1935.

The special rules and directives set forth in Oil and Gas Docket 10-77,314 (LTX product reports and classification) and the related staff memorandum of September 24, 1985 are retained. The Staff Memorandum of December 17, 1973 (District 10—Lease-wide Testing) is rescinded. All other prior fieldwide rules, directives and memoranda are hereby superceded and rescinded, including but not limited to the following:

Date	Docket No.	Purpose
08/27/30	112	Establishing Field Rules
11/01/30	112	Amending 8/27/30 Order
01/23/31	112	Establishing Field Rules
04/04/31	113	Establishing Field Rules
10/13/31	108	Time limits on drilling
10/30/31	108	Establishing Field Rules
10/30/31	108	Common Purchaser Law
10/30/31	122, 119	Rules governing common purchasers
05/09/32	108	25% Open Flow Limit
06/15/32	None	Oil and Gas Circular 15
11/18/32	108	Granting Exemptions
12/06/32	108	Establishing Field Fules
12/30/32	108	Determining Allowable Production
12/30/32	108	Establishing Field Rules
10/17/33	None	Adopting Circular 16-B
05/12/34	108	Amending Rule 2
05/15/34	None	Readopting Circular 16-B
05/24/35	108	Reducing Potentials
07/20/35	108	Fixing Allowable Gas Production
08/01/35	108	Fixing Allowable Gas Production
08/05/35	108	Fixing Allowable Gas Production
08/06/35	108	Changing Method of Taking Potentials
08/28/35	108	Fixing Allowable Gas Production
09/25/35	108	Fixing Allowable Gas Production
10/17/35	108	Fixing Allowable Gas Production
10/23/35	108	Regarding Pending Court Proceedings
11/22/35	108	Changing Method of Taking Potentials
12/10/35	108	Fixing Allowable Gas Production
01/14/36	108	Authorizing Gas-Oil Ratio Survey
02/03/36	108	Amending Above

Date	Docket No.	Purpose
04/27/36	108	Revoking Authorization of Survey
09/15/36	108	Authorizing Gas-Oil Ratio Survey
02/25/37	108	Setting a Gas-Oil Ratio
10/02/37	10-93	Limiting Gas Volumes
11/18/37	20-169	Fixing Allowable Gas Production
05/04/38	10-316	Fixing Allowable Gas Production
05/25/38	10-338	Amending Above
10/15/38	10-453	Setting Out Rules
11/25/38	10-499	Limiting Gas Volumes
01/14/39	10-548	Amending Above
01/18/39	20-550	Classifying Condensate Wells
01/31/39	10-564	Fixing Allowable Gas Production
04/01/39	10-621	Supplementing Above
01/11/40	10-1222	Amending Circular 16-B
03/12/40	10-1384	Promulgating Spacing Rule
03/25/40	10-1449	Fixing Allowable Gas Production
03/28/40	10-1445	Amending Circular 16-B
04/30/40	10-1543	Suspending Above
07/08/40	10-1685	Repressurization of Oil Sands
08/23/40	10-1832	Amending Circular 16-B
11/20/40	10-2080	Fixing Classification Method
08/29/41	10-2898	Amending Circular 16-B
11/13/41	10-3087	Limiting Gas Volumes
04/06/42	10-3593	Limiting Gas Production
10/29/42	10-4135	Limiting Gas Production
05/19/43	10-4833	Limiting Gas Production
08/14/44	10-6600	Amending Spacing Rules
11/14/45	10-8333	West Pampa Repressurization
05/24/48	10-12,465	Requiring Well Tests
09/24/48	10-13,196	Sweet and Sour Gas
01/10/49	10-13,783	Amending Above
02/06/50	10-17,595	Amending Above
03/04/52	10-23,060	Determination of Absolute Potentials
12/19/51	10-22,479	Roughness Friction Factor
06/09/52	10-23,807	Amending Order No. 10-13,196
06/30/52	10-23,955	Rescinding Order No. 10-23,807
07/21/52	10-24,144	Amending Order No. 10-23,060
09/18/52	10-24,493	Gas Measurement Rules
05/19/54	10-29,542	Gas Well Testing Rules
05/19/54	10-29,544	Gas Well Testing Rules

Date	Docket No.	Purpose
08/30/54	10-30,121	Amending Rule 3(c)
11/07/55	10-32,363	Revising East Field Rules
09/16/57	10-36,290	Requiring Gas-Oil Ratio Surveys
11/22/60	10-44,633	East Field Operating Rules
10/11/77	10-67,681	GOR Test Procedures

Done this —— day of ————, 1988.

RAILROAD COMMISSION OF TEXAS

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Chairman

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Commissioner

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Commissioner

ATTEST:

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Secretary

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[Appendices Omitted in Printing]